MidCon Compression LP
Form 424B2
December 01, 2006
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Filed pursuant to Rule 424(b)(2)
Registration No. 333-139053

PROSPECTUS

600,000,000

6 1/4% Senior Notes due 2017

The Company:

Chesapeake Energy Corporation is the third largest independent producer of natural gas in the United States and owns interests in approximately 33,700 producing oil and natural gas wells.

The Offering:

Use of Proceeds: We intend to use the net proceeds from this offering to repay outstanding indebtedness under our revolving bank credit facility, which may be reborrowed for general corporate purposes, including to finance potential future acquisitions.
Interest: The notes have a fixed annual rate of 6.25% which will be paid every six months on January 15 and July 15, commencing July 15, 2007.
Maturity: January 15, 2017.

Guarantees: The notes will be guaranteed on a senior unsecured basis by each of our existing United States subsidiaries, other than certain de minimis subsidiaries, and one of our non-United States subsidiaries.
Ranking: The notes will be our senior unsecured obligations and will rank equally in right of payment with all of our existing and future senior debt and senior to any subordinated debt that we may incur. The notes will be effectively subordinated to our and our guarantor subsidiaries existing and future secured debt, including debt under our revolving bank credit facility, to the extent of the value of the assets securing such debt. The notes will also be effectively subordinated to the debt of any non-guarantor subsidiaries.
Change of Control: Upon the occurrence of certain change of control events, each holder of notes may require us to repurchase all or a portion of its notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued interest.
Tax Redemption: We may redeem the notes in whole but not in part at 100% of their principal amount plus accrued interest if at any time we became obligated to pay withholding taxes as a result of a change in law.
Make-Whole Redemption: We may redeem some or all of the notes at any time pursuant to certain make-whole provisions. If we enter into certain sale-leaseback transactions and do not reinvest the proceeds or repay certain senior debt, we must offer to repurchase the notes.
Pricing:

	Per Note	Total
Initial public offering price	100.000%	600,000,000
Underwriting discount	1.625%	9,750,000
Proceeds, before expenses, to Chesapeake	98.375%	590,250,000

This investment involves risks. See Risk Factors beginning on page 14.

The underwriters expect to deliver the notes to investors on or about December 6, 2006, only in book-entry form through the facilities of Euroclear and Clearstream. We intend to apply to list the notes on the Irish Stock Exchange for trading on the Alternative Securities Market thereof.

Joint Book-Running Managers

Barclays Capital

Sole Global Coordinator

Credit Suisse

Deutsche Bank Securities

Goldman Sachs International

Senior Co-Managers

ABN AMRO
Banc of America Securities Limited
BNP PARIBAS
Fortis Securities
Lehman Brothers
The Royal Bank of Scotland plc
UBS Investment Bank

Co-Managers

Bayerische Hypo- und Vereinsbank AG
BMO Capital Markets
Calyon Securities (USA)
DZ Financial Markets LLC
Natexis Bleichroeder Inc.
RBC Capital Markets
TD Securities

The date of this prospectus is December 1, 2006.

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We have not authorized any dealer, salesperson or other person to give any information or represent anything to you other than the information contained in this prospectus. You must not rely on unauthorized information or representations. The information in this prospectus is current only as of the date on its cover, and may change after that date.

NOTICE TO INVESTORS

This prospectus does not constitute an offer or solicitation by anyone in any jurisdiction in which such offer or solicitation is not authorized or to any person to whom it is unlawful to make such offer or solicitation. No action has been, or will be, taken to permit a public offering in any jurisdiction where action would be required for that purpose other than the United States. Accordingly, the notes may not be offered or sold, directly or indirectly, and this prospectus may not be distributed, in any jurisdiction except in accordance with the legal requirements applicable in such jurisdiction. You must comply with all laws applicable in any jurisdiction in which you buy, offer or sell the notes or possess or distribute this prospectus, and you must obtain all applicable consents and approvals; neither we nor the underwriters shall have any responsibility for any of the foregoing legal requirements.

Neither we nor the underwriters nor any of our or their respective representatives is making any representation to you regarding the legality of an investment in the notes, and you should not construe anything in this prospectus as legal, business, tax or other advice. You should consult your own advisors as to the legal, tax, business, financial and related aspects of an investment in the notes. In making an investment decision regarding the notes, you must rely on your own examination of the issuer and the terms of the offering, including the merits and risks involved.

By accepting delivery of this prospectus, you agree not to use any information herein for any purpose other than considering an investment in the notes.

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Subject to the following paragraph, we accept responsibility for the information contained in this prospectus. We have made all reasonable inquiries and confirm to the best of our knowledge, information and belief that the information contained in this prospectus with regard to our Subsidiaries and our affiliates and the notes is true and accurate in all material respects, that the opinions and intentions expressed in this prospectus are honestly held and that we are not aware of any other facts the omission of which would make this prospectus or any statement contained herein misleading in any material respect.

The information contained under the caption Exchange Rate Information includes extracts from information and data publicly released by official and other sources. While we accept responsibility for accurately summarizing the information concerning exchange rate information, we accept no further responsibility in respect of such information. The information set out in relation to sections of this prospectus describing clearing and settlement arrangements, including the section entitled Description of Notes Book-Entry, Delivery and Form, is subject to any change in or reinterpretation of the rules, regulations and procedures of Euroclear Bank S.A./N.V. (Euroclear) or Clearstream Banking, socièté anonyme (Clearstream) currently in effect. While we accept responsibility for accurately summarizing the information concerning Euroclear or Clearstream, we accept no further responsibility in respect of such information. In addition, this prospectus contains summaries believed to be accurate with respect to certain documents, but reference is made to the actual documents for complete information. All such summaries are qualified in their entirety by such reference. Copies of documents referred to herein will be made available to prospective investors upon request to us.

The underwriters, the trustee, the paying agents and any other agents acting with respect to the notes accept no responsibility for and make no representation or warranty, express or implied, as to the accuracy or completeness of the information set forth in this prospectus and nothing contained in this prospectus is, or should be relied upon as, a promise or representation by the underwriters, the trustee, the paying agents or any other agents acting with respect to the notes as to the past or the future.

By purchasing the notes, you will be deemed to have acknowledged that you have reviewed this prospectus and have had an opportunity to request, and have received, all additional information that you need from us. No person is authorized in connection with any offering made by this prospectus to give any information or to make any representation not contained in this prospectus and, if given or made, any other information or representation must not be relied upon as having been authorized by us or the underwriters.

The information contained in this prospectus is as of the date hereof. Neither the delivery of this prospectus at any time after the date of publication nor any subsequent commitment to purchase the notes shall, under any circumstances, create an implication that there has been no change in the information set forth in this prospectus or in our business since the date of this prospectus.

The notes will be issued in the form of one or more global notes, which will be deposited with, or on behalf of, a common depositary for the accounts of Euroclear and Clearstream. Beneficial interests in the global notes will be shown on, and transfers of beneficial interests in the global notes will be effected only through, records maintained by Euroclear and/or Clearstream and their participants, as applicable. See Description of Notes Book-Entry, Delivery and Form.

This prospectus sets out the procedures of Euroclear and Clearstream in order to facilitate the original issue and subsequent transfers of interests in the notes among participants of Euroclear and Clearstream. However, neither Euroclear nor Clearstream is under any obligation to perform or continue to perform such procedures and such procedures may be modified or discontinued by either of them at any time. We will not, nor will any of our agents, have responsibility for the performance of the respective obligations of Euroclear, Clearstream or their respective participants under the rules and procedures

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governing their operations, nor will we or our agents have any responsibility or liability for any aspect of the records relating to, or payments made on account of, book-entry interests held through the facilities of any clearing system or for maintaining, supervising or reviewing any records relating to these book-entry interests. Investors wishing to use these clearing systems are advised to confirm the continued applicability of their rules, regulations and procedures.

Neither the U.S. Securities and Exchange Commission (the SEC), any state securities commission nor any non-U.S. securities authority has approved or disapproved of these securities or determined that this prospectus is accurate or complete. Any representation to the contrary is a criminal offense.

We reserve the right to withdraw this offering of the notes at any time. We and the underwriters also reserve the right to reject any offer to purchase the notes in whole or in part for any reason or no reason and to allot to any prospective purchaser less than the full amount of the notes sought by it. The underwriters and certain of their respective related entities may acquire, for their own accounts, a portion of the notes.

We cannot guarantee that our application to list the notes on the Irish Stock Exchange for trading on the Alternative Securities Market thereof will be approved as of the settlement date for the notes or at any time then after, and settlement of the notes is not conditioned on obtaining this listing.

The underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the notes. Specifically, the underwriters may over-allot in connection with this offering and may bid for and purchase notes in the open market. For a description of these activities, see Underwriting.

NOTICE TO CERTAIN EUROPEAN INVESTORS

Austria. The notes may be offered and sold in Austria only in accordance with the provisions of the Banking Act, the Securities Supervision Act of Austria (*Bankwesengesetz and Wertpapieraufsichtsgesetz*) and any other applicable Austrian law. The notes have not been admitted to public offer in Austria under the provisions of the Capital Markets Act or the Investment Fund Act or the Exchange Act (*Kapitalmarktgesetz, Investmentfondsgesetz or Börsengesetz*). Consequently, in Austria, the notes may not be offered or sold directly or indirectly by way of a public offering in Austria and will only be available to a limited group of persons within the scope of their professional activities.

Belgium. The offering of the notes does not constitute an offer to the public in Belgium. It is only directed to persons who are qualified investors (within the meaning of Article 2.1(e)(i) to (iii) of the Prospectus Directive or, upon its implementation, of the relevant Belgian act implementing the Prospectus Directive).

Denmark. This prospectus has not been filed with or approved by any authority in the Kingdom of Denmark. The notes have not been offered or sold and may not be offered, sold or delivered directly or indirectly in the Kingdom of Denmark, except to qualified investors within the meaning of, or otherwise in compliance with an exemption set forth in, Executive Order No. 306 of 28 April 2005.

France. The notes have not been and will not be offered or sold to the public in France (*appel public à l épargne*), and no offering or marketing materials relating to the notes must be made available or distributed in any way that would constitute, directly or indirectly, an offer to the public in the Republic of France.

The notes may only be offered or sold in the Republic of France to qualified investors (*investisseurs qualifiés*) and/or to a limited group of investors (*cercle restreint d investisseurs*) as defined in and in accordance with articles L.411-1 and L.411-2 of the French *Code monétaire et financier* and Decree n°98-880 dated October 1, 1998.

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Prospective investors are informed that:

(i) this prospectus has not been submitted for clearance to the French financial market authority (*Autorité des Marchés Financiers*);

(ii) in compliance with Decree n°98-880 dated October 1, 1998, any investors subscribing for the notes should be acting for their own account; and

(iii) the direct and indirect distribution or sale to the public of the notes acquired by them may only be made in compliance with articles L.411-1, L.411-2, L.412-1 and L.621-8 of the *French Code monétaire et financier*.

Germany. The offering of the notes is not a public offering in the Federal Republic of Germany. The notes may be offered and sold in the Federal Republic of Germany only in accordance with the provisions of the Securities Prospectus Act of the Federal Republic of Germany (*Wertpapierprospektgesetz, WpPG*) and any other applicable German law. Consequently, in Germany, the notes will only be available to and this prospectus and any other offering material in relation to the notes is directed only at persons who are qualified investors (*qualifizierte Anleger*) within the meaning of Section 2 No. 6 of the Securities Prospectus Act and the notes must not be publicly offered, and this prospectus and any other offering material in relation to the notes must not be passed on, to any person in Germany other than such qualified investor. Any resale of the notes in Germany may only be made in accordance with the Securities Prospectus Act and other applicable laws.

Ireland. The notes may be offered or sold in Ireland only in accordance with the European Communities (Stock Exchange) Regulations 1984, the European Communities (Transferable Securities and Stock Exchange) Regulations 1992, the Investment Intermediaries Act, 1995 (as amended) and the Companies Act 1963 to 2001 and all other applicable Irish laws and regulations.

Italy. The offering of the notes in Italy has not been registered with the Commissione Nazionale per le Società e la Borsa (CONSOB) pursuant to Italian securities legislation and, accordingly: (i) the notes cannot be offered, sold or delivered in the Republic of Italy (Italy) in a solicitation to the public at large (*sollecitazione all investimento*) within the meaning of Article 1, paragraph 1, letter (t) of Legislation Decree no. 58 of February 24, 1998 (the Financial Services Act), nor may any copy of this prospectus or any other document relating to the notes be distributed in Italy, (ii) the notes cannot be offered, sold and/or delivered, nor may any copy of this prospectus or any other document relating to the notes be distributed, either in the primary or in the secondary market, to individuals resident in Italy, and (iii) sales of the notes in Italy shall only be: (a) negotiated with Professional Investors (*operatori qualificati*), as defined under Article 31, paragraph 2, of CONSOB Regulation no. 11522 of July 1, 1998, as amended (CONSOB Regulation 11522), (b) effected in compliance with Article 129 of the Legislative Decree no. 385 of September 1, 1993 (the Italian Banking Act) and the implementing instructions of the Bank of Italy, (c) made by an investment firm, bank or financial intermediary permitted to conduct such activities in Italy in accordance with the Italian Banking Act, the Financial Services Act, CONSOB Regulation 11522 and all the other relevant provisions of Italian law and (d) effected in accordance with any other Italian securities, tax and exchange control and other applicable laws and regulations and any other applicable requirement or limitation which may be imposed by CONSOB or the Bank of Italy. Insofar as the requirements above are based on laws which are suspended at any time pursuant to the Prospectus Directive, such requirements shall be replaced by the applicable requirements under the Prospectus Directive or the relevant implementing laws.

Grand Duchy of Luxembourg. This offering should not be considered a public offering in the Grand Duchy of Luxembourg. This prospectus may not be reproduced or used for any purpose other than this offering, nor provided to any person other than the recipient thereof. The notes are offered to a limited

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number of sophisticated investors in all cases under circumstances designed to preclude a distribution, which would be other than a private placement. All public solicitations are banned and the sale may not be publicly advertised.

The Netherlands. Each of the underwriters represents and agrees that (a) it is a professional market party (PMP) within the meaning of Section 1(e) of the Exemption Regulation of June 26, 2002 in respect of the Act on the Supervision of the Credit System 1992 (*Vrijstellingsregeling Wtk 1992*), as amended from time to time (the Exemption Regulation), where applicable read in conjunction with the policy rules of the Dutch Central Bank (*de Nederlandsche Bank N.V.*) on key concepts of market access and enforcement of the Act on the Supervision of the Credit System 1992 (*Wet toezicht Kredietwezen 1992*) published on December 29, 2004 (*Beleidsregel 2005 kernbegrippen markttoetreding en handhaving Wtk 1992*) (the Policy Rules), and Section 2 of the Policy Rules, as amended, supplemented and restated from time to time and (b) it has offered or sold and will offer or sell, directly or indirectly, as part of the initial distribution or at any time thereafter, the notes exclusively (i) to PMPs as reasonably identified by the Issuer on the issue date or (ii) to persons which cannot reasonably be identified as PMPs by the Issuer on the issue date, provided that the notes have a denomination of 50,000 (or the equivalent in any other currency) and shall upon their issuance be included in a clearing institution that is established in an EU Member State, the United States, Japan, Australia, Canada or Switzerland; so that it can reasonably be expected that the underwriters will transfer the notes exclusively to other PMPs.

Generally, notes (including rights representing an interest in a global note) may not be offered, sold, transferred or delivered at any time by anyone, directly or indirectly, to individuals or legal entities who or which are established, domiciled or have their residence in The Netherlands (Dutch Residents) other than to PMPs acquiring the notes for their own account. Dutch Residents, by purchasing notes (or any interest therein), will be deemed to have represented and agreed for the benefit of the Issuer that they are a PMP and acquire the notes for their own account. Each holder of the notes , by purchasing notes (or any interest therein), will be deemed to have represented and agreed for the benefit of the Issuer that (i) such notes (or any interest herein) may not be offered, sold, pledged or otherwise transferred to Dutch Residents other than to a PMP acquiring for its own account or for the account of another PMP and (ii) they will provide notice of this transfer restriction to any subsequent transferee.

In addition, and without prejudice to the relevant restrictions set out above, the notes that are offered in The Netherlands may only be offered and such an offer may only be announced: (i) if the notes have a denomination of at least 50,000 or the equivalent in any other currency; (ii) if the notes, irrespective of their denomination, can be acquired only as a package for a consideration of at least 50,000 or the equivalent in any other currency; and/or (iii) to professional market parties within the meaning of Section 1a paragraph 3 of the Exemption Regulation to the Dutch Securities Supervision Act 1995 (*Vrijstellingsregeling Wet toezicht effectenverkeer 1995*); and otherwise (iv) in accordance with the Dutch Securities Supervision Act 1995 (*Wet toezicht effectenverkeer 1995*) and corresponding regulations, as amended from time to time.

Spain. The notes may not be offered or sold in Spain except in accordance with the requirements of the Spanish Securities Market Law (*Ley 24/1988, de 28 de julio, del Mercado de Valores*), as amended and restated, and Royal Decree 291/1992, on issues and public offerings for the sale of securities (*Real Decreto 291/1992, de 27 de marzo, sobre emisiones y ofertas públicas de venta de valores*), as amended and restated, and the decrees and regulations made thereunder. The notes may not be listed, sold, offered or distributed to persons in Spain except (i) in circumstances which do not constitute an offer of securities in Spain within the meaning of Spanish Securities Market Law and further relevant legislation or (ii) pursuant to Article 7 of Royal Decree 291/1992 and subject to compliance with the registration requirements set out therein. This prospectus has not been registered with the Spanish Securities Market Commission (*Comisión Nacional del Mercado de Valores*) and therefore it is not intended for the offering or sale of the notes in Spain.

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Sweden. This prospectus has not been and will not be registered with the Swedish Financial Supervisory Authority. Accordingly, this prospectus may not be made available, nor may the notes otherwise be marketed and offered for sale, in Sweden other than in circumstances that are deemed not to be an offer to the public under the Financial Instruments Trading Act (1991:980).

Switzerland. The offering of the notes is not a public offering in Switzerland. The notes have not been and will not be offered, directly or indirectly, to the public in Switzerland and this prospectus does not constitute a public offering prospectus as that term is understood pursuant to art. 1156 of the Swiss Federal Code of Obligations.

United Kingdom. This prospectus is for distribution only to persons who (i) have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (as amended, the Financial Promotion Order), (ii) are persons falling within Article 49(2)(a) to (d) (high net worth companies, unincorporated associations, etc) of the Financial Promotion Order or (iii) are persons to whom an invitation or inducement to engage in investment activity (within the meaning of section 21 of the Financial Services and Markets Act 2000) in connection with the issue or sale of any notes may otherwise lawfully be communicated or caused to be communicated (all such persons together being referred to as relevant persons). This prospectus is directed only at relevant persons and must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this document relates is available only to relevant persons and will be engaged in only with relevant persons. The notes are being offered solely to qualified investors as defined in the Prospectus Directive and accordingly the offer of notes is not subject to the obligation to publish a prospectus within the meaning of the Prospectus Directive.

NOTICE TO NEW HAMPSHIRE RESIDENTS

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENSE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE REVISED STATUTES (RSA 421-B) WITH THE STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE OF THE STATE OF NEW HAMPSHIRE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER OR CLIENT ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

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EXCHANGE RATE INFORMATION

In this prospectus, (i) or euro refers to the single currency of the participating Member States in the Third Stage of the European Economic and Monetary Union of the Treaty Establishing The European Community, as amended from time to time, and (ii) $ or dollars refers to the lawful currency of the United States.

The following chart shows for the period from January 1, 2001 through November 30, 2006, the period end, average, high and low noon buying rates in the City of New York for cable transfers of euro as certified for customs purposes by the Federal Reserve Bank of New York expressed as dollars per 1.00.

	dollars per 1.00			
Year	**High**	**Low**	**Period average[1]**	**Period end**
2001	0.9535	0.8370	0.8909	0.8901
2002	1.0485	0.8594	0.9495	1.0485
2003	1.2597	1.0361	1.1411	1.2597
2004	1.3625	1.1801	1.2478	1.3538
2005	1.3476	1.1667	1.2400	1.1842
Month				
January 2006	1.2287	1.1980	1.2126	1.2158
February 2006	1.2100	1.1860	1.1940	1.1925
March 2006	1.2197	1.1886	1.2028	1.2139
April 2006	1.2624	1.2091	1.2273	1.2624
May 2006	1.2888	1.2607	1.2767	1.2833
June 2006	1.2953	1.2522	1.2661	1.2779
July 2006	1.2822	1.2500	1.2681	1.2764
August 2006	1.2914	1.2735	1.2810	1.2793
September 2006	1.2833	1.2648	1.2722	1.2687
October 2006	1.2773	1.2502	1.2617	1.2773
November 2006	1.3261	1.2705	1.2888	1.3261

(1) Period average represents the average of the noon buying rates on the last business day of each month during the relevant period for yearly information and the average of the noon buying rates on each business day during the period for monthly information.

The above rates may differ from the actual rates used in the preparation of the consolidated financial statements and other financial information appearing in this prospectus or incorporated by reference herein. Our inclusion of these exchange rates is not meant to suggest that the dollar amounts actually represent such euro amounts or that such amounts could have been converted into euro at any particular rate, if at all.

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SUMMARY

This summary may not contain all the information that may be important to you. You should read this entire prospectus and the documents to which we have referred you before making an investment decision. You should carefully consider the information set forth under Risk Factors. In addition, certain statements include forward-looking information which involves risks and uncertainties. See Forward-Looking Statements.

Chesapeake

We are the third largest independent producer of natural gas in the United States, and we own interests in approximately 33,700 producing oil and natural gas wells that are currently producing approximately 1.69 billion cubic feet equivalent, or bcfe, per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the U.S. east of the Rocky Mountains. Our most important operating area has historically been in various conventional plays in the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At September 30, 2006, 47% of our proved oil and natural gas reserves were located in the Mid-Continent region. During the past four years, we have also built significant positions in various conventional and unconventional plays 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 Texas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Fayetteville Shale in Arkansas, the Barnett and Woodford Shales in West Texas and the Conasauga, Floyd and Chattanooga Shales of Alabama.

As of December 31, 2005, we had 7.5 trillion cubic feet equivalent, or tcfe, of proved reserves, of which 92% were natural gas and all of which were onshore. During 2005, we produced an average of 1.3 bcfe per day, a 30% increase over the 1.0 bcfe per day produced in 2004. For 2005, we generated net income available to common shareholders of $880 million, or $2.51 per fully diluted common share, which was a 64% increase over the prior year. For the year ended December 31, 2005, we had total revenues of $4.67 billion and an EBITDA of $2.66 billion and, for the nine months ended September 30, 2006, we had total revenues of $5.46 billion and an EBITDA of $3.77 billion. Please see note 4 to Summary Consolidated Financial Data.

During the first three quarters of 2006, we led the nation in drilling activity with an average utilization of 89 operated rigs and 74 non-operated rigs. Through this drilling activity, we drilled 1,024 (845 net) operated wells and participated in another 1,154 (141 net) wells operated by other companies. Our success rate was 98% for operated and non-operated wells. We replaced our 426 bcfe of production with an internally estimated 1.339 tcfe of new proved reserves for a reserve replacement rate of 314%. Reserve replacement through the drillbit was 825 bcfe, or 194% of production (including 541 bcfe of positive performance revisions and 387 bcfe of downward revisions resulting from oil and natural gas price declines between December 31, 2005 and September 30, 2006), and reserve replacement through acquisitions was 514 bcfe, or 120% of production. As a result, our proved reserves grew by 12% during the first three quarters of 2006, from 7.5 tcfe to 8.4 tcfe. Of the 8.4 tcfe, 63% were proved developed reserves.

In the first three quarters of 2006, we produced an average of 1.6 bcfe per day, a 26% increase over the 1.2 bcfe per day produced in the first three quarters of 2005. During the first three quarters of 2006, we generated net income available to common shareholders of $1.459 billion, or $3.40 per fully diluted common share, which was a 158% increase over the first three quarters of 2005. Also, in the first three quarters of 2006 we added approximately 1,700 new employees to support our growth, which increased our total employee base to approximately 4,600 employees at September 30, 2006, and invested $558

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million in leasehold (excluding leasehold 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 September 30, 2006, we have been one of the most active consolidators of onshore U.S. natural gas assets, having purchased approximately 6.4 tcfe of proved reserves, at a total cost of approximately $13.4 billion (including $4.3 billion for unproved leasehold, but excluding $987 million of deferred taxes established in connection with certain corporate acquisitions). Excluding the amounts allocated to unproved leasehold and deferred taxes, our acquisition cost per proved thousand cubic feet equivalent, or mcfe, was $1.42 over this time period. During 2006, we have remained active in the acquisitions market. Acquisition expenditures in 2006 totaled $3.1 billion (including $2.1 billion for unproved leasehold). Through these acquisitions, we will have acquired an internally estimated 514 bcfe of proved oil and natural gas reserves.

We intend to use the net proceeds from this offering to repay outstanding indebtedness under our revolving bank credit facility, which may be reborrowed for general corporate purposes, including to finance potential future acquisitions. Please see Use of Proceeds.

Our executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, and our telephone number is (405) 848-8000.

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 much of the past eight years, our strategy to accomplish this goal has been to build a dominant operating position in the Mid-Continent region, the third largest natural 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 region 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 Texas and eastern New Mexico, the Barnett Shale area of North Texas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Fayetteville Shale in Arkansas, the Barnett and Woodford Shales in West Texas and the Conasauga, Floyd and Chattanooga Shales of Alabama. 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 high potential deep drilling opportunities. From January 1, 1998 through September 30, 2006, we have purchased approximately 6.4 tcfe of proved reserves, at a total cost of approximately $13.4 billion (including $4.3 billion for unproved leasehold, but excluding $987 million of deferred taxes established in connection with certain corporate acquisitions). Excluding the amounts allocated to unproved leasehold and deferred taxes, our acquisition cost per proved mcfe was $1.42 over this time period. 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

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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 Chesapeake s most distinctive characteristics is our ability to increase reserves and production through the drillbit. We are currently utilizing 122 operated drilling rigs and 99 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 much of the past eight years, we have been actively investing in leasehold, 3-D seismic information and human capital to be able to take advantage of the favorable drilling economics that exist today. While we believe U.S. natural gas production has declined during the past five years, we are one of the few large-cap independent oil and gas companies that have been able to increase production, which we have successfully achieved for the past 16 consecutive years and 21 consecutive quarters. We believe key elements of the success and scale of our drilling programs have been our early recognition that natural gas prices were likely to move higher in the U.S. in the post-1999 period accompanied by our willingness to proactively hire new employees and to build the nation s largest onshore leasehold and 3-D seismic inventories, all of which are the building blocks of a successful large-scale drilling program.

Build Regional Scale. We believe one of the keys to success in the natural gas exploration industry is to build significant operating scale in a limited number of operating areas that share many similar geological and operational characteristics. Achieving such scale provides many benefits, the most important of which are higher per unit revenues, lower per unit operating costs, greater rates of drilling success, higher returns from more easily integrated acquisitions and higher returns on drilling investments. We first began pursuing this focused strategy in the Mid-Continent region in late 1997 and we are now the largest natural gas producer, the most active driller and the most active acquirer of leasehold and producing properties in the Mid-Continent. We believe this region, which trails only the Gulf Coast and Rocky Mountain basins in 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 94% over the past 17 years, generally lower service costs than in more competitive or more remote basins and a favorable regulatory environment with virtually no federal land ownership. We believe our other operating areas possess many of these same favorable characteristics and our goal is to become or remain a top five natural gas 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 extensive and competitive services, natural gas processing and transportation infrastructures that exist in our key operating areas. As of September 30, 2006, we operated approximately 19,800 wells, which accounted for approximately 83% of our daily production volume. This large percentage of operated properties provides us with a high degree of operating flexibility and cost control.

Improve our Balance Sheet. We have made significant progress in improving our balance sheet over the past seven years. From December 31, 1998 through September 30, 2006, we have increased our shareholders equity by $10.4 billion through a combination of earnings and common and preferred equity issuances. As of September 30, 2006, our debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 44%, compared to 137% as of December 31, 1998. On a pro forma basis for this offering, our debt to total capitalization ratio as of

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September 30, 2006, would also have been 44%. 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 natural gas supply and the growing demand for this clean-burning, U.S.-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 7% 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 seventh largest producer of natural gas in the U.S. (third among independents) and the fourth largest owner of proved U.S. natural gas reserves (first among independents). In each of our operating areas, our properties are concentrated in locations that enable us to establish substantial economies of scale in drilling and production operations and facilitate the application of more effective reservoir management practices. We intend to continue building our asset base in each of our operating areas through a balance of acquisitions, exploitation and exploration.

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 the first three quarters of 2006, our operating costs per unit of production were $1.38 per mcfe, which consisted of general and administrative expenses of $0.23 per mcfe (including non-cash stock-based compensation of $0.05 per mcfe), production expenses of $0.85 per mcfe and production taxes of $0.30 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 natural gas transportation infrastructures and considerable potential for further consolidation of assets. Since 1998, we have acquired approximately 6.4 tcfe of proved reserves that replaced 281% of our total production. We believe we are well-positioned to continue making attractive acquisitions as a result of our extensive track record of identifying, completing and integrating multiple successful acquisitions, our large operating scale and our knowledge and experience in the regions in which we operate.

Large Inventory of Drilling Projects. During the 17 years since our inception, we have been among the five most active drillers of new wells in the United States. Presently we are the most active driller in the U.S. with 122 operated and 99 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

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search of large natural gas accumulations in challenging conventional and unconventional reservoirs. As a result of our successful acquisition program and active leasehold acquisition and seismic acquisition strategies, we have been able to accumulate a U.S. onshore leasehold position of approximately 10.5 million net acres, and have acquired rights to 14.7 million acres of onshore 3-D seismic data to provide informational advantages over our competitors and to help evaluate our large acreage inventory. On this very large acreage position, our technical teams believe approximately 25,000 exploratory and developmental drill sites exist, 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. As of September 30, 2006, we had natural gas hedges in place covering 57%, 57% and 51% of our anticipated natural gas production for the fourth quarter of 2006 and all of 2007 and 2008, respectively, at average NYMEX prices of $9.10, $9.61 and $9.37 per mcf, respectively. In addition, we have 88%, 72% and 59% of our anticipated oil production hedged for the remainder of 2006 and all of 2007 and 2008, respectively, at average NYMEX prices of $65.64, $71.42 and $71.45 per barrel of oil, respectively. During the first three quarters of 2006, we realized gains from our hedging program of approximately $807 million.

Entrepreneurial Management. Our management team formed the company in 1989 with an initial capitalization of $50,000 and fewer than ten employees. Since then, our management team has guided the company through various operational and industry challenges and extremes of oil and natural gas prices to create the third largest independent producer of natural gas in the U.S. with approximately 4,600 employees and an enterprise value of approximately $25 billion (pro forma for this offering). Our chief executive officer and co-founder, Aubrey K. McClendon, has been in the oil and natural gas industry for 25 years and beneficially owns, as of November 30, 2006, approximately 25.4 million shares of our common stock.

Other Developments

In the past year, there has been significant focus on corporate governance and accounting practices in the grant of equity based awards to executives and employees of publicly traded companies, including the use of market hindsight to select award dates to favor award recipients. Like many other public companies, we have in recent months received occasional investor inquiries regarding our practices in granting employee and executive stock options in past years. On our own initiative and under the auspices of our audit committee, we undertook an internal review of our practices in this area, primarily for the purpose of confirming that the past accounting treatment of our equity compensation awards was appropriate. Recently, we received an investor inquiry questioning the timing of several option grants during the period from 1995 to 2003 in relation to the trading price of our common stock. We expanded our internal review to review these specific option grants and the results were reported to our audit committee. While these internal reviews revealed deficiencies in the documentation of our option grants in prior years, there was no evidence of any misconduct by our executives or directors in the timing or selection of our option grant dates, or that would cause us to conclude that our prior accounting for stock option grants was incorrect in any material respect.

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The Offering

The summary below describes the principal terms of the notes. Some of the terms and conditions described below are subject to important limitations and exceptions. The Description of Notes section of this prospectus contains a more detailed description of the terms and conditions of the notes.

Issuer	Chesapeake Energy Corporation.
Notes Offered	600,000,000 in aggregate principal amount of 6.25% Senior Notes due 2017.
Maturity Date	January 15, 2017.
Interest	Interest on the notes will accrue at an annual rate of 6.25%. Interest will be paid semi-annually in arrears on January 15 and July 15 of each year, commencing July 15, 2007.
Guarantees	The notes will be unconditionally guaranteed, jointly and severally, by (i) each of our existing United States subsidiaries, other than certain de minimis subsidiaries, and one of our non-United States subsidiaries and (ii) each of our future United States subsidiaries that guarantees any other indebtedness of us or a subsidiary guarantor in excess of $5 million. The guarantee will be released if we dispose of the subsidiary guarantor or it ceases to guarantee certain other indebtedness of us or any other subsidiary guarantor.
Ranking	The notes will be unsecured and will rank equally in right of payment to all of our existing and future senior indebtedness. The notes will rank senior in right of payment to all of our future subordinated indebtedness. Holders of our secured indebtedness have claims with respect to our assets constituting collateral for their indebtedness that are prior to your claim under the notes. In addition, the notes will be structurally subordinated to any indebtedness of a subsidiary that is not a subsidiary guarantor. Please read Description of Notes Ranking.
	As of September 30, 2006, we had approximately $8.0 billion in principal amount of senior indebtedness outstanding, of which $1.5 billion was secured indebtedness under our revolving bank credit facility. After giving effect to this offering and the application of net proceeds therefrom as described under Use of Proceeds, on a pro forma basis as of September 30, 2006, we would have had approximately $8.0 billion in principal amount of senior indebtedness outstanding, $685.1 million of which would have been secured indebtedness. As of November 30, 2006, we had outstanding borrowings of $1.952 billion under our revolving bank credit facility.

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Make-Whole Redemption	We may redeem some or all of the notes at any time prior to maturity by the payment of a make-whole premium described in the Description of Notes Make-Whole Redemption section of this prospectus.
Change of Control	Upon the occurrence of certain change of control events, each holder of notes may require us to repurchase all or a portion of its notes at a purchase price equal to 101% of the principal amount of the notes, plus accrued interest.
Restrictive Covenants	The indenture governing the notes will contain covenants that limit our ability and our subsidiaries ability to: incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The covenants are subject to a number of exceptions and qualifications. See Description of Notes Certain Covenants.
Additional Amounts	Any payments made by us with respect to the notes will be made without withholding or deduction for taxes imposed by any relevant taxing jurisdiction unless required by law. If we are required by law to withhold or deduct for taxes with respect to a payment to the holders of notes, we will pay additional amounts necessary so that the net amount received by the holders of notes after the withholding is not less than the amount that they would have received in the absence of the withholding. See Description of Notes Payment of Additional Amounts.
Redemption for Taxation Reasons	In the event that we become obligated to pay additional amounts (as described above) to holders of the notes as a result of changes affecting withholding taxes applicable to payments on the notes, we may redeem the notes in whole but not in part at any time at 100% of the principal amount of the notes plus accrued interest to the date of redemption. See Description of Notes Redemption Upon Changes in Withholding Taxes.
Use of Proceeds	We expect the net proceeds to us from this offering, after deducting discounts to the underwriters and estimated expenses of the offering payable by us, will be approximately 590.1 million (or approximately $778.9 million based on a dollar/euro exchange rate of approximately $1.32 to 1.00 as of November 30, 2006). We intend to use the net proceeds from this offering to repay outstanding indebtedness under our revolving bank credit facility, which may be reborrowed for general corporate purposes, including funding potential future acquisitions. Please see Use of Proceeds.
Listing	We intend to apply to list the notes on the Irish Stock Exchange for trading on the Alternative Securities Market thereof.

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Denomination	The notes will be issued in denominations of 50,000 and in any integral multiples of 1,000 in excess of 50,000.
Book-Entry, Delivery and Form	Initially, the notes will be represented by one or more permanent global certificates in definitive, fully registered form deposited with a custodian for, and registered in the name of, a nominee of a common depositary for the accounts of Euroclear and Clearstream.

Risk Factors

An investment in the notes involves certain risks that a potential investor should carefully evaluate prior to making an investment in the notes. Please read Risk Factors beginning on page 14.

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Summary Consolidated Financial Data

The following tables set forth summary consolidated financial data as of and for each of the three years ended December 31, 2005, 2004 and 2003 and nine months ended September 30, 2006 and 2005. This data was derived from our audited consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2005 and from our unaudited condensed consolidated financial statements included in our quarterly report on Form 10-Q for the quarterly period ended September 30, 2006, each of which is incorporated by reference herein and included in Annex A and Annex B, respectively. The financial data below should be read together with, and is qualified in its entirety by reference to, our historical consolidated financial statements and the accompanying notes and the Management s Discussion and Analysis of Financial Condition and Results of Operations which are set forth in such annual report on Form 10-K and quarterly report on Form 10-Q.

	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2004	2003	2006	2005
	($ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and natural gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822	$ 4,190,430	$ 2,032,271
Oil and natural gas marketing sales	1,392,705	773,092	420,610	1,170,091	882,040
Service operations revenue				97,473	
Total revenues	4,665,290	2,709,268	1,717,432	5,457,994	2,914,311
Operating costs:					
Production expenses	316,956	204,821	137,583	364,134	222,660
Production taxes	207,898	103,931	77,893	129,858	136,313
General and administrative expenses	64,272	37,045	23,753	99,728	39,640
Oil and natural gas marketing expenses	1,358,003	755,314	410,288	1,131,521	860,789
Service operations expense				48,925	
Oil and natural gas depreciation, depletion and amortization	894,035	582,137	369,465	976,839	621,484
Depreciation and amortization of other assets	50,966	29,185	16,793	74,051	34,791
Employee retirement expense				54,753	
Provision for legal settlements		4,500	6,402		
Total operating costs	2,892,130	1,716,933	1,042,177	2,879,809	1,915,677
Income from operations	1,773,160	992,335	675,255	2,578,185	998,634
Other income (expense):					
Interest and other income	10,452	4,476	2,827	19,742	7,790
Interest expense	(219,800)	(167,328)	(154,356)	(220,226)	(155,623)
Loss on repurchases or exchanges of Chesapeake senior notes	(70,419)	(24,557)	(20,759)		(70,047)
Gain on sale of investment				117,396	
Loss on investment in Seven Seas			(2,015)		
Total other income (expense)	(279,767)	(187,409)	(174,303)	(83,088)	(217,880)
Income before income taxes and cumulative effect of accounting change	1,493,393	804,926	500,952	2,495,097	780,754
Income tax expense (benefit):					
Current			5,000		

Deferred	545,091	289,771	185,360	963,136	284,977
Total income tax expense (benefit)	545,091	289,771	190,360	963,136	284,977
Net income before cumulative effect of accounting change, net of tax	948,302	515,155	310,592	1,531,961	495,777
Cumulative effect of accounting change, net of income taxes of $1,464,000			2,389		
Net Income	948,302	515,155	312,981	1,531,961	495,777
Preferred stock dividends	(41,813)	(39,506)	(22,469)	(62,793)	(25,526)
Loss on conversion/exchange of preferred stock	(26,874)	(36,678)		(10,556)	(22,468)
Net income available to common shareholders	$ 879,615	$ 438,971	$ 290,512	$ 1,458,612	$ 447,783

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	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2004	2003	2006	2005
	($ in thousands, except per share data)				
Earnings per common share basic:					
Income before cumulative effect of accounting change	$ 2.73	$ 1.73	$ 1.36	$ 3.75	$ 1.42
Cumulative effect of accounting change			0.02		
	$ 2.73	$ 1.73	$ 1.38	$ 3.75	$ 1.42
Earnings per common share assuming dilution:					
Income before cumulative effect of accounting change	$ 2.51	$ 1.53	$ 1.20	$ 3.40	$ 1.32
Cumulative effect of accounting change			0.01		
	$ 2.51	$ 1.53	$ 1.21	$ 3.40	$ 1.32
Cash dividends declared per common share	$ 0.195	$ 0.170	$ 0.135	$ 0.170	$ 0.145
Cash Flow Data:					
Cash provided by operating activities	$ 2,406,888	$ 1,432,274	$ 938,907	$ 2,982,419	$ 1,577,345
Cash used in investing activities	6,921,378	3,381,204	2,077,217	6,668,005	3,655,044
Cash provided by financing activities	4,567,621	1,915,245	931,254	3,626,275	2,197,905
Other Financial Data:					
Ratio of earnings to fixed charges(1)(2)	5.6x	4.8x	4.0x	7.7x	4.3x
Ratio of earnings to fixed charges and preference dividends(1)(2)	4.6x	3.7x	3.3x	6.0x	3.7x
Ratio of total debt to EBITDA	2.1x	1.9x	2.0x		
EBITDA(3)	$ 2,658,194	$ 1,583,576	$ 1,041,566	$ 3,766,213	$ 1,592,652

	As of December 31,			As of September 30,	
	2005	2004	2003	2006	2005
	($ in thousands)				
Balance Sheet Data:					
Total assets	$ 16,118,462	$ 8,244,509	$ 4,572,291	$ 23,394,921	$ 12,365,629
Long-term debt, net	5,489,742	3,075,109	2,057,713	7,861,108	4,250,160
Stockholders equity	6,174,323	3,162,883	1,732,810	10,192,820	4,206,320

(1) For purposes of determining the ratios of earnings to fixed charges and earnings to fixed charges and preference dividends, earnings are defined as net income before income taxes, cumulative effect of accounting changes, pretax gain or loss of equity investees, amortization of capitalized interest and fixed charges, less capitalized interest. Fixed charges consist of interest (whether expensed or capitalized and excluding the effect of unrealized gains or losses on interest rate derivatives), and amortization of debt expenses and discount or premium relating to any indebtedness. Preference dividends consist of preferred stock dividends grossed up to reflect the pre-tax amount.

(2) The ratio of earnings to fixed charges for the years ended December 31, 2001 and 2002 was 4.4x and 1.5x, respectively. The ratio of earnings to fixed charges and preference dividends for the years ended December 31, 2001 and 2002 was 4.2x and 1.3x, respectively.

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(3) EBITDA represents net income before income tax expense, interest expense, oil and natural gas depreciation, depletion and amortization and depreciation and amortization of other assets. EBITDA is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. EBITDA is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our revolving bank credit facility and is used in the financial covenants in our revolving bank credit facility and our senior note indentures. EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP. EBITDA is reconciled to net income as follows:

	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2004	2003	2006	2005
	($ in thousands)				
Net income	$ 948,302	$ 515,155	$ 312,981	$ 1,531,961	$ 495,777
Income tax expense	545,091	289,771	190,360	963,136	284,977
Interest expense	219,800	167,328	154,356	220,226	155,623
Oil and natural gas depreciation, depletion and amortization	894,035	582,137	369,465	976,839	621,484
Depreciation and amortization of other assets	50,966	29,185	16,793	74,051	34,791
Cumulative effect of accounting change			(2,389)		
EBITDA	$ 2,658,194	$ 1,583,576	$ 1,041,566	$ 3,766,213	$ 1,592,652

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Summary Reserve Information

The following table sets forth our estimated proved reserves and the present value of the proved reserves as of December 31, 2005 (based on our weighted average wellhead prices at December 31, 2005 of $56.41 per barrel of oil and $8.76 per mcf of natural gas). These prices were based on the cash spot prices for oil and natural gas at December 31, 2005.

	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
Appalachia	1,094	1,289,919	1,296,482	17	3,462,744
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
South Texas and Texas Gulf Coast	3,308	602,551	622,399	8	2,459,379
Other	4,501	14,858	41,787	1	110,965
Total	103,323	6,900,754	7,520,690	100%	$ 22,933,594(1)

(1) The standardized measure of discounted future net cash flows at December 31, 2005 was $16.0 billion.

As of December 31, 2005, the present value of our proved developed reserves as a percentage of total proved reserves was 71%, and the volume of our proved developed reserves as a percentage of total proved reserves was 65%. Natural gas reserves accounted for 92% of the volume of total proved reserves at December 31, 2005.

Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate. A change in price of $0.10 per mcf for natural gas and $1.00 per barrel for oil would result in a change in our December 31, 2005 present value of estimated future net revenue of proved reserves of approximately $315 million and $50 million, respectively.

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Summary Production, Sales, Prices and Expenses Data

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

	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2004	2003	2006	2005
Net Production:					
Oil (mbbl)	7,698	6,764	4,665	6,437	5,684
Natural gas (mmcf)	422,389	322,009	240,366	387,696	304,060
Natural gas equivalent (mmcfe)	468,577	362,593	268,356	426,318	338,164
Oil and Natural Gas Sales ($ in thousands):					
Oil sales	$ 401,845	$ 260,915	$ 132,630	$ 404,595	$ 290,332
Oil derivatives realized gains (losses)	(34,132)	(69,267)	(12,058)	(25,695)	(28,654)
Oil derivatives unrealized gains (losses)	4,374	3,454	(9,440)	24,825	(5,951)
Total oil sales	$ 372,087	$ 195,102	$ 111,132	$ 403,725	$ 255,727
Natural gas sales	$ 3,231,286	$ 1,789,275	$ 1,171,050	$ 2,526,168	$ 2,005,670
Natural gas derivatives realized gains (losses)	(367,551)	(85,634)	(5,331)	832,769	(97,955)
Natural gas derivatives unrealized gains (losses)	36,763	37,433	19,971	427,768	(131,171)
Total natural gas sales	$ 2,900,498	$ 1,741,074	$ 1,185,690	$ 3,786,705	$ 1,776,544
Total oil and natural gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822	$ 4,190,430	$ 2,032,271
Average Sales Price: (excluding gains (losses) on derivatives):					
Oil ($ per bbl)	$ 52.20	$ 38.57	$ 28.43	$ 62.85	$ 51.08
Natural gas ($ per mcf)	$ 7.65	$ 5.56	$ 4.87	$ 6.52	$ 6.60
Natural gas equivalent ($ per mcfe)	$ 7.75	$ 5.65	$ 4.86	$ 6.87	$ 6.79
Average Sales Price: (excluding unrealized gains (losses) on derivatives):					
Oil ($ per bbl)	$ 47.77	$ 28.33	$ 25.85	$ 58.86	$ 46.04
Natural gas ($ per mcf)	$ 6.78	$ 5.29	$ 4.85	$ 8.66	$ 6.27
Natural gas equivalent ($ per mcfe)	$ 6.90	$ 5.23	$ 4.79	$ 8.77	$ 6.42
Expenses ($ per mcfe):					
Production expenses	$ 0.68	$ 0.56	$ 0.51	$ 0.85	$ 0.66
Production taxes	$ 0.44	$ 0.29	$ 0.29	$ 0.30	$ 0.40
General and administrative expenses	$ 0.14	$ 0.10	$ 0.09	$ 0.23	$ 0.12
Oil and natural gas depreciation, depletion and amortization	$ 1.91	$ 1.61	$ 1.38	$ 2.29	$ 1.84
Depreciation and amortization of other assets	$ 0.11	$ 0.08	$ 0.06	$ 0.17	$ 0.10
Interest expense[(1)]	$ 0.47	$ 0.45	$ 0.55	$ 0.52	$ 0.47

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

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RISK FACTORS

In addition to the other information set forth elsewhere or incorporated by reference in this prospectus, the following factors relating to our company and the offering should be considered carefully before making an investment in the notes offered hereby.

Risks Relating to Our Business

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

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

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

- worldwide and United States supplies of oil and 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 imports in the United States;
- United States and non-United States governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;

political instability or armed conflict in oil-producing regions; and

overall United States and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Declines in oil and natural gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 92% of our reserves at December 31, 2005 were natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness and preferred stock may adversely affect operations and limit our growth, and we may have difficulty making debt service payments on our indebtedness as such payments become due.

As of September 30, 2006, we had long-term indebtedness of approximately $7.9 billion, with $1.5 billion of outstanding borrowings drawn under our revolving bank credit facility. Our long-term indebtedness represented 44% of our total book capitalization at September 30, 2006. As of November 30, 2006, we had approximately $1.952 billion outstanding under our revolving bank credit facility. We expect to continue to be highly leveraged in the foreseeable future.

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

- a portion of our cash flows from operating activities must be used to service our indebtedness and pay dividends on our preferred stock and is not available for other purposes;
- we may be at a competitive disadvantage as compared to similar companies that have less debt;
- the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;
- changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving bank credit facility; and
- we may be more vulnerable to general adverse economic and industry conditions.

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

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

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

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

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

Many of our competitors have financial and other resources substantially greater than ours, and some of them are fully integrated oil companies. These companies may be able to pay more for development prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and

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purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to develop and exploit our oil and natural gas properties and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing and producing new reserves. If revenues were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to 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 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 35% of our total estimated proved reserves (by volume) at December 31, 2005 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 24% from 2006 to 2007. 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 prospectus and the documents incorporated by reference herein contain estimates of our proved reserves and the estimated future net revenues from our proved reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

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

At December 31, 2005, approximately 35% 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

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expenditures to develop the reserves, including approximately $1.8 billion in 2006. 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 prospectus and the documents incorporated by reference herein represent the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The December 31, 2005 present value is based on weighted average oil and natural gas wellhead prices of $56.41 per barrel of oil and $8.76 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 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 recent growth is due in large part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

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

Significant acquisitions present operational and administrative challenges that may prove more difficult than anticipated. The failure to consolidate functions and integrate procedures, personnel and operations in an effective and timely manner may adversely affect our business and results of operations, at least temporarily. Significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties in our primary operating areas or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as in our prior acquisitions.

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

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

- 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 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 gas at that date, adjusted for the impact of derivatives accounted for as cash flow hedges. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future writedown of capitalized costs and a non-cash charge against future earnings.

At December 31, 2005, our net book value of oil and natural gas properties less deferred income taxes was below the calculated ceiling by approximately $6.5 billion. From December 31, 2005 to September 30, 2006, spot natural gas prices decreased by approximately 59% from $10.08 to $4.18 per mcf. As a result, as of September 30, 2006, our ceiling test calculation indicated an impairment of our oil and natural gas properties of approximately $415 million. However, natural gas prices subsequent to September 30, 2006 have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting in the third quarter of 2006.

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 gas, we enter into oil and gas price risk management arrangements for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce oil and natural gas revenues in the future. The fair value of our oil and gas derivative instruments outstanding as of September 30, 2006 was an asset of approximately $1.476 billion. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our revolving bank credit facility or directly pledging oil and gas properties, rather than posting cash or letters of credit with the counterparties. As of September 30, 2006, we had outstanding collateral allocations and pledges of oil and gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our revolving bank credit facility. As of November 30, 2006, we had outstanding transactions with thirteen counterparties, seven of which hold collateral allocations from our revolving bank credit facility or liens against certain oil and gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. As of November 30, 2006, we were not required to post cash or letters of credit with the remaining four counterparties. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

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

Our revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments (currently both are $2.5 billion). The borrowing base is determined periodically at the discretion of the banks and is based in part on oil and natural gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our revolving bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in the relevant indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. As of the date of this prospectus, we are permitted to incur significant additional indebtedness under both of these debt incurrence tests. Lower oil and gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

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

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

injury or loss of life;

severe damage to or destruction of property, natural resources and equipment;

pollution or other environmental damage;

clean-up responsibilities;

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regulatory investigations and administrative, civil and criminal penalties; and

injunctions resulting in limitation or suspension of operations.

There is inherent risk of incurring significant environmental costs and liabilities in our exploration and production operations due to our generation, handling, and disposal of materials including wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and wastes on, under or from our leased or owned properties, some of which have been used for oil and natural gas exploration and production activities for a number of years, oftentimes by third parties not under our control. While we may maintain insurance against some, but not all, of the risks described above, our insurance may not be adequate to cover casualty losses or liabilities. Also, in the future we may not be able to obtain insurance at premium levels that justify its purchase.

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

Risks Related to the Notes

Holders of the notes will be effectively subordinated to all of our and our subsidiaries secured indebtedness.

Holders of our secured indebtedness, which is comprised primarily of the indebtedness under our revolving bank credit facility, have claims with respect to our assets constituting collateral for their indebtedness that are prior to your claims under the notes. In the event of a default on the notes or our bankruptcy, liquidation or reorganization, those assets would be available to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on the notes. Accordingly, the secured indebtedness would effectively be senior to the notes to the extent of the value of the collateral securing the indebtedness. While the indenture governing the notes places some limitations on our ability to create liens, there are significant exceptions to these limitations, including with respect to sale and leaseback transactions, that will allow us to secure indebtedness without equally and ratably securing the notes. To the extent the value of the collateral is not sufficient to satisfy the secured indebtedness, the holders of that indebtedness would be entitled to share with the holders of the notes and the holders of other claims against us with respect to our other assets. In addition, in certain circumstances a subsidiary may not be required to be, or may be delayed in becoming, a Subsidiary Guarantor. The notes will be structurally subordinated to any indebtedness of a subsidiary that is not a Subsidiary Guarantor.

A guarantee could be voided if the guarantor fraudulently transferred the guarantee at the time it incurred the indebtedness, which could result in the noteholders being able to rely on only us to satisfy claims.

Under U.S. bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims under a guarantee may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time it incurred the indebtedness evidenced by its guarantee:

- intended to hinder, delay or defraud any present or future creditor or received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee;

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was insolvent or rendered insolvent by reason of such incurrence;

was engaged in a business or transaction for which the guarantor s remaining assets constituted unreasonably small capital; or

intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

In addition, any payment by that guarantor under a guarantee could be voided and required to be returned to the guarantor or to a fund for the benefit of the creditors of the guarantor.

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon the governing law. Generally, a guarantor would be considered insolvent if:

the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all of its assets;

the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they became absolute and mature; or

it could not pay its debts as they became due.

On the basis of historical financial information, recent operating history and other factors, we believe that the subsidiary guarantees are being incurred for proper purposes and in good faith and that each subsidiary guarantor, after giving effect to its guarantee of the notes, will not be insolvent, have unreasonably small capital for the business in which it is engaged or have incurred debts beyond its ability to pay those debts as they mature. We cannot be certain, however, that a court would agree with our conclusions in this regard.

You may find it difficult to sell your notes.

The notes will constitute a new issue of securities with no established public market. Although the underwriters have indicated that they intend to make a market in the notes, they are not obligated to do so and any of their market making activities may be terminated or limited at any time. In addition, although we have registered the offer and sale of the notes under the Securities Act of 1933 and intend to apply for a listing of the notes on the Irish Stock Exchange for trading on the Alternative Securities Market, there can be no assurance as to the liquidity of markets that may develop for the notes, the ability of noteholders to sell their notes or the prices at which notes could be sold. The notes may trade at prices that are lower than their initial purchase price depending on many factors, including prevailing interest rates and the markets for similar securities. The liquidity of trading markets for the notes may also be adversely affected by general declines or disruptions in the markets for debt securities. Those market declines or disruptions could adversely affect the liquidity of and market for the notes independent of our financial performance or prospects. An active market for the notes may not develop or, if developed, may not continue. In the absence of an active trading market, you may not be able to transfer the notes within the time or at the price you desire.

The notes lack some covenants typically found in other comparably rated public debt securities.

Although the notes are rated below investment grade by both Standard & Poor s and Moody s Investors Service, they lack the protection for holders of several financial and other restrictive covenants associated with several other series of our outstanding senior notes and typically associated with comparably rated public debt securities, including:

incurrence of additional indebtedness;

payment of dividends and other restricted payments;

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sale of assets and the use of proceeds therefrom;

transactions with affiliates; and

dividend and other payment restrictions affecting subsidiaries.

The principal amount of the notes and interest thereon contained in our financial statements may be adversely affected by fluctuations in the dollar/euro exchange rate.

Since our financial statements are presented in dollars, fluctuations in the dollar/euro exchange rate could adversely affect the principal amount of the notes and the amount of interest payments made on the notes reflected in our financial statements. Since the payments related to the notes will be made in euro, we will need to convert dollars into euro to make such payments, which could result in an increase or decrease in the dollar equivalent of interest payments on the notes depending on fluctuations in the exchange rate. In addition, because our financial results are reported in dollars, the outstanding principal amount of the notes will be reported in dollars based on the average exchange rate for the euro prevailing during the reporting period or the exchange rate at the end of that period. If such exchange rate declines, the amount of debt represented by the notes reflected in our financial statements in dollars will increase.

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USE OF PROCEEDS

We expect the net proceeds from this offering to be approximately 590.1 million (or approximately $778.9 million based on a dollar/euro exchange rate of approximately $1.32 to 1.00 as of November 30, 2006), after deducting underwriters discounts and the estimated expenses of the offering payable by us. We intend to use the net proceeds from this offering to repay borrowings under our revolving bank credit facility, which may be reborrowed for general corporate purposes, including funding potential future acquisitions. Affiliates of certain of the underwriters in this offering are lenders under our existing revolving bank credit facility and may receive a portion of the proceeds from this offering. See Underwriting. As of September 30, 2006, the average interest rate on borrowings outstanding under our revolving bank credit facility was 6.53%.

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CAPITALIZATION

The following table shows our unaudited capitalization as of September 30, 2006:

on a historical basis; and

on a pro forma basis to reflect this offering.

This table should be read in conjunction with, and is qualified in its entirety by reference to, our historical financial statements and the accompanying notes included in our annual report on Form 10-K for the year ended December 31, 2005, and our quarterly report on Form 10-Q for the quarter ended September 30, 2006, which are incorporated by reference herein and included in Annex A and Annex B, respectively.

	As of September 30, 2006	
	Historical	Pro Forma
	($ in thousands)	
Cash and cash equivalents	$ 716	$ 716
Long-term debt:		
Revolving bank credit facility(1)	$ 1,464,000	$ 685,120
7.500% Senior Notes due 2013	363,823	363,823
7.625% Senior Notes due 2013	500,000	500,000
7.000% Senior Notes due 2014	300,000	300,000
7.500% Senior Notes due 2014	300,000	300,000
7.750% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	600,000
6.875% Senior Notes due 2016	670,437	670,437
6.500% Senior Notes due 2017	1,100,000	1,100,000
6.250% Senior Notes due 2017 offered hereby		792,000(2)
6.250% Senior Notes due 2018	600,000	600,000
6.875% Senior Notes due 2020	500,000	500,000
2.750% Contingent Convertible Senior Notes due 2035	690,000	690,000
Interest rate derivatives	(23,621)	(23,621)
Discount, net of premium, on Senior Notes	(103,939)	(103,939)
Total long-term debt	$ 7,861,108	$ 7,874,228
Stockholders equity:		
Preferred stock, $0.01 par value, 20,000,000 authorized:		
5.00% Cumulative Convertible Preferred Stock (Series 2003), 38,625 shares issued and outstanding, entitled in liquidation to $3.9 million	3,863	3,863
4.125% Cumulative Convertible Preferred Stock, 3,065 shares issued and outstanding, entitled in liquidation to $3.1 million	3,065	3,065
5.00% Cumulative Convertible Preferred Stock (Series 2005), 4,600,000 shares issued and outstanding, entitled in liquidation to $460.0 million	460,000	460,000
4.50% Cumulative Convertible Preferred Stock, 3,450,000 shares issued and outstanding, entitled in liquidation to $345.0 million	345,000	345,000
	575,000	575,000

5.00% Cumulative Convertible Preferred Stock (Series 2005B), 5,750,000 shares issued and outstanding, entitled in liquidation to $575.0 million		
6.25% Mandatory Convertible Preferred Stock, 2,300,000 shares issued and outstanding, entitled in liquidation to $575.0 million	575,000	575,000
Common stock, $0.01 par value, 750,000,000 shares authorized, 437,859,397 issued and outstanding	4,379	4,379
Paid-in capital	4,899,634	4,899,634
Retained earnings	2,495,215	2,495,215
Accumulated other comprehensive income (loss), net of tax of ($518,564,000)	862,241	862,241
Less: treasury stock, at cost; 1,306,528 common shares	(30,577)	(30,577)
Total stockholders equity	$ 10,192,820	$ 10,192,820
Total capitalization	$ 18,053,928	$ 18,067,048

(1) As of November 30, 2006, we had outstanding borrowings of $1.952 billion under our revolving bank credit facility.
(2) Based on an assumed public offering price of par and the dollar/euro exchange rate as of November 30, 2006 of approximately $1.32 per 1.00.

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DESCRIPTION OF NOTES

Chesapeake Energy Corporation will issue the notes offered hereby (the Notes) under an indenture to be dated as of December 6, 2006 (the Indenture), among the Company, as issuer, the Subsidiary Guarantors, as guarantors, The Bank of New York Trust Company, N.A., as trustee (the Trustee), The Bank of New York, London Branch, as registrar, transfer agent and paying agent, and AIB/BNY Fund Management (Ireland) Limited, as Irish paying agent and transfer agent. The terms of the Notes include those stated in the Indenture and those made part of the Indenture by reference to the Trust Indenture Act of 1939 (the Trust Indenture Act).

The following description is only a summary of the material provisions of the Notes and the Indenture. These descriptions do not purport to be complete and are subject to, and are qualified in their entirety by reference to, the Notes and the Indenture. You may request copies of the Indenture at our address set forth under the heading Where You Can Find More Information.

Certain terms used in this description are defined under the subheading Certain Definitions. In this description, the words Company, we and our refer only to Chesapeake Energy Corporation and not to any of its Subsidiaries.

General

The Company will issue the Notes initially with a maximum aggregate principal amount of 600 million. The Company is permitted to issue additional Notes under the Indenture in an unlimited aggregate principal amount (Add-On Notes). Any Add-On Notes that are actually issued will be treated as issued and outstanding Notes (as the same class as the initial Notes) for all purposes of the Indenture and this Description of Notes, unless the context indicates otherwise. Each Note will mature on January 15, 2017 and will bear interest at the rate of interest per annum indicated on the cover page of this prospectus.

Interest on the Notes issued in this offering will accrue from the Issue Date at an annual rate of 6.25%, payable semi-annually in arrears on January 15 and July 15 of each year, commencing July 15, 2007. We will make each interest payment to the Holders of record of the Notes at the close of business on January 1 or July 1 preceding such interest payment date. Interest will be computed on the basis of a 360-day year of twelve 30-day months. Principal, premium, if any, and interest will be payable at the offices of the Trustee and the paying agents, *provided* that, at the option of the Company, payment of interest on Notes not in global form may be made by check mailed to the address of the Person entitled thereto as it appears in the register of the Notes maintained by the registrar. Initially, The Bank of New York, London Branch will act as registrar, transfer agent and paying agent for the Notes in London, England, and AIB/BNY Fund Management (Ireland) Limited will act as paying agent and transfer agent in Dublin, Ireland.

The Notes are unsecured senior obligations of the Company. The Notes rank pari passu in right of payment with all existing and future Senior Indebtedness of the Company and rank senior in right of payment to all future Subordinated Indebtedness of the Company.

Guarantees

On the Issue Date, all the existing United States Subsidiaries, other than certain de minimis Subsidiaries, and one non-United States Subsidiary of the Company will fully and unconditionally guarantee, on a joint and several basis, the Company s obligations to pay principal of, premium, if any, and interest on the Notes. The Indenture provides that each Person that becomes a United States Subsidiary after the Issue Date and guarantees any other Indebtedness of the Company or a Subsidiary Guarantor in excess of a De Minimis Guaranteed Amount will guarantee the payment of the Notes within 180 days after the later of (i) the date it becomes a United States Subsidiary and (ii) the date it guarantees such other Indebtedness, provided that no guarantee shall be required if the Subsidiary merges into the Company or an existing Subsidiary Guarantor and the surviving entity remains a Subsidiary Guarantor.

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The obligations of each Subsidiary Guarantor under its Guarantee will be limited as necessary to prevent that Guarantee from constituting a fraudulent conveyance or fraudulent transfer under federal, state or non-United States law. Each Subsidiary Guarantor that makes a payment or distribution under a Guarantee shall be entitled to a contribution from each other Subsidiary Guarantor in a pro rata amount based on the respective net assets of each Subsidiary Guarantor at the time of such payment determined in accordance with GAAP.

If a Guarantee were rendered voidable, it could be subordinated by a court to all other indebtedness (including guarantees and other contingent liabilities) of the applicable Subsidiary Guarantor, and, depending on the amount of such indebtedness, a Subsidiary Guarantor s liability on its Guarantee could be reduced to zero. Please read Risk Factors Risks Related to the Notes A guarantee could be voided if the guarantor fraudulently transferred the guarantee at the time it incurred the indebtedness, which could result in the noteholders being able to rely on only us to satisfy claims.

Subject to the next succeeding paragraph, no Subsidiary Guarantor may consolidate or merge with or into (whether or not such Subsidiary Guarantor is the surviving Person) another Person unless:

(1) the Person formed by or surviving any such consolidation or merger (if other than such Subsidiary Guarantor) assumes all the obligations of such Subsidiary Guarantor under the Indenture and the Notes pursuant to a supplemental indenture, in a form reasonably satisfactory to the Trustee, and

(2) immediately after such transaction, no Default or Event of Default exists.

The preceding does not prohibit a merger between Subsidiary Guarantors or a merger between the Company and a Subsidiary Guarantor. In the event of a sale or other disposition of all or substantially all of the assets of any Subsidiary Guarantor, or a sale or other disposition of all the Capital Stock of such Subsidiary Guarantor, in any case whether by way of merger, consolidation or otherwise, then such Subsidiary Guarantor (in the event of a sale or other disposition by way of such a merger, consolidation or otherwise, of all of the Capital Stock of such Subsidiary Guarantor) or the Person acquiring the assets (in the event of a sale or other disposition of all or substantially all of the assets of such Subsidiary Guarantor) will be released and relieved of any obligations under its Guarantee. Further, a Subsidiary Guarantor will be released and relieved from any obligations under its Guarantee if it ceases to guarantee any other Indebtedness of the Company or any other Subsidiary Guarantor other than a De Minimis Guaranteed Amount.

Ranking

Senior Indebtedness versus Notes. The Indebtedness evidenced by the Notes and the Guarantees will be unsecured and will rank pari passu in right of payment to all Senior Indebtedness of the Company and the Subsidiary Guarantors, as the case may be.

As of September 30, 2006, the Company and the Subsidiary Guarantors had approximately $8.0 billion in principal amount of Senior Indebtedness outstanding, $1.5 billion of which was secured indebtedness under our revolving bank credit facility. Upon completion of this offering, and the ultimate application of the net proceeds therefrom as described under Use of Proceeds, we would have had, on a pro forma basis as of September 30, 2006, approximately $8.0 billion in principal amount of Senior Indebtedness outstanding, $685.1 million of which would have been secured. As of November 30, 2006, we had outstanding borrowings of $1.952 billion under our revolving bank credit facility.

The Notes will be unsecured obligations of the Company. Secured debt and other secured obligations of the Company and the Subsidiary Guarantors (including obligations with respect to our revolving bank credit facility) will be effectively senior to the Notes to the extent of the value of the assets securing such debt or other obligations.

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Liabilities of Subsidiaries versus Notes. A substantial portion of the Company s operations is conducted through its Subsidiaries. Claims of creditors of any Subsidiaries that are not Subsidiary Guarantors, including trade creditors and creditors holding indebtedness or guarantees issued by such Subsidiaries, and claims of preferred stockholders of such Subsidiaries will have priority with respect to the assets and earnings of such Subsidiaries over the claims of the Company s creditors, including Holders of the Notes. Accordingly, the Notes will be effectively subordinated to creditors (including trade creditors) and preferred stockholders, if any, of Subsidiaries that are not Subsidiary Guarantors.

Although the Indenture limits the incurrence of certain secured Indebtedness by the Company s Subsidiaries, such limitations are subject to a number of significant qualifications and the Indenture does not limit the incurrence of unsecured Indebtedness.

Make-Whole Redemption

At any time prior to the Maturity Date, the Company may, at its option, redeem all or any portion of the Notes at the Make-Whole Price plus accrued and unpaid interest to the date of redemption.

Redemption Upon Changes in Withholding Taxes

If, as a result of:

(a) any amendment to, or change in, the laws (or regulations or rulings promulgated thereunder) of any Relevant Taxing Jurisdiction (as defined below under Payment of Additional Amounts); or

(b) any change in the official application or the official interpretation or administration of such laws, regulations or rulings (including a holding, judgment or order by a court of competent jurisdiction or a change in published practice) (each of the foregoing in clauses (a) and (b), a Change in Tax Law),

the Company, any Subsidiary Guarantor or any Successor (as defined below under Certain Covenants Limitations on Mergers and Consolidations) would be obligated to pay, on the next date for any payment, Additional Amounts, as described below under Payment of Additional Amounts, which the Company, such Subsidiary Guarantor or such Successor cannot avoid by the use of reasonable measures available to it (including making payment through a paying agent located in another jurisdiction), then the Company or the Successor, as the case may be, may redeem all, but not less than all, of the Notes at any time after such amendment or change, upon not less than 30 nor more than 60 days notice, at a redemption price of 100% of their principal amount, plus accrued and unpaid interest, if any, to the redemption date. In the case of the United States or any other jurisdiction that is a Relevant Taxing Jurisdiction on the Issue Date, the applicable Change in Tax Law must become effective on or after the date of this prospectus. In the case of a jurisdiction that becomes a Relevant Taxing Jurisdiction after the Issue Date, the applicable Change in Tax Law must become effective after the date that such jurisdiction becomes a Relevant Taxing Jurisdiction.

Prior to the giving of any notice of redemption described in this paragraph, the Company or the Successor, as the case may be, will deliver to the Trustee:

(i) an officers certificate of the Company or the Successor, as the case may be, stating that the obligation to pay such Additional Amounts cannot be avoided by the Company, such Subsidiary Guarantor or such Successor taking reasonable measures available to it; and

(ii) a written opinion of independent legal counsel of recognized standing addressed to the Company or the Successor, as the case may be, to the effect that the Company, such Subsidiary

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Guarantor or such Successor has or will become obligated to pay such Additional Amounts as a result of a Change in Tax Law described above.

Absent manifest error, the Trustee will accept such officers certificate and opinion as sufficient evidence of the satisfaction of the conditions to a redemption upon a Change in Tax Law, including any changes in withholding taxes, in which event it will be conclusive and binding on the Holders of the Notes.

Notwithstanding the foregoing, no such notice will be given (a) earlier than 90 days prior to the earliest date on which the Company or the relevant Successor or Subsidiary Guarantor, as the case may be, would be obliged to pay such Additional Amounts if a payment were then due and (b) unless at the time such notice is given, such obligation to pay such Additional Amounts remains in effect.

Payment of Additional Amounts

All payments that the Company or any Successor makes under or with respect to the Notes, or that any Subsidiary Guarantor makes with respect to any Guarantee, will be made free and clear of, and without withholding or deduction for or on account of, any present or future tax, duty, levy, impost, assessment or other governmental charges (including, without limitation, penalties, interest and other similar liabilities related thereto) of whatever nature (collectively, Taxes) imposed or levied by or on behalf of any jurisdiction in which the Company, or, if applicable, any Subsidiary Guarantor or any Successor, as the case may be, is incorporated, organized or otherwise resident for tax purposes or from or through which any of the foregoing makes any payment on the Notes or by any taxing authority therein or political subdivision thereof (each, as applicable, a Relevant Taxing Jurisdiction), unless the Company, such Subsidiary Guarantor or such Successor, as the case may be, is required to withhold or deduct Taxes by law or by the interpretation or administration of law. If the Company, a Subsidiary Guarantor or such Successor is required to withhold or deduct any amount for, or on account of, Taxes of a Relevant Taxing Jurisdiction from any payment made under or with respect to the Notes or any Guarantee, the Company, such Subsidiary Guarantor or such Successor, as the case may be, will pay such additional amounts (Additional Amounts) as may be necessary to ensure that the net amount received by each Holder of the Notes after such withholding or deduction will be not less than the amount the Holder would have received if such Taxes had not been required to be withheld or deducted.

Notwithstanding the foregoing, neither the Company, any Subsidiary Guarantor nor any Successor will, however, be required to pay Additional Amounts to a Holder or beneficial owner of Notes in respect of or on account of:

(a) any Taxes that are imposed or levied by a Relevant Taxing Jurisdiction by reason of the Holder s or beneficial owner s present or former connection with such Relevant Taxing Jurisdiction, including, without limitation, the Holder or beneficial owner being or having been a citizen, national, or resident, being or having been engaged in a trade or business, being, or having been, physically present in or having or having had a permanent establishment in a Relevant Taxing Jurisdiction (but not including, in each case, any connection arising from the mere receipt or holding of Notes or the receipt of payments thereunder or under a Guarantee or the exercise or enforcement of rights under any Notes or the Indenture or a Guarantee);

(b) any Taxes that are imposed or levied by reason of the failure of the Holder or beneficial owner of Notes, following the written request of the Company, any Subsidiary Guarantor or any Successor (as the case may be) addressed to the Holder (and made at a time that would enable the Holder or beneficial owner acting reasonably to comply with that request) made in accordance with the notice procedures set forth in the Indenture, to comply with any certification, identification, information or other reporting requirements, whether required by statute, treaty, regulation or administrative practice of a Relevant Taxing Jurisdiction, as a precondition to exemption from, or reduction in the rate of withholding or deduction of, Taxes imposed by the

Relevant Taxing Jurisdiction (including, without limitation, a certification that the Holder or beneficial owner is not resident in the Relevant Taxing Jurisdiction);

(c) any estate, inheritance, gift, sales, transfer, personal property or similar Taxes;

(d) any Tax that is payable otherwise than by withholding or deduction from payments made under or with respect to the Notes;

(e) any Tax that is imposed or levied by reason of the presentation (where presentation is required in order to receive payment) of such Notes for payment on a date more than 30 days after the date on which such payment became due and payable or the date on which payment thereof is duly provided for, whichever is later, except to the extent that the beneficial owner or Holder thereof would have been entitled to Additional Amounts had the Notes been presented for payment on any date during such 30 day period;

(f) any withholding or deduction in respect of any Taxes where such withholding or deduction is imposed or levied on a payment to an individual and is required to be made pursuant to European Council Directive 2003/48/EC or any other Directive implementing the conclusions of the ECOFIN Council meeting of November 26-27, 2000 on the taxation of savings income or any law implementing or complying with, or introduced in order to conform to, such Directive;

(g) any Tax that is imposed or levied on or with respect to a payment made to a Holder or beneficial owner who would have been able to avoid such withholding or deduction by presenting the Notes to another paying agent in a Member State of the European Union; or

(h) any combination of items (a) through (g) above.

Furthermore, Additional Amounts will not be paid with respect to the Notes to a Holder who is a fiduciary, a partnership, a limited liability company or other than the sole beneficial owner of the payment under or with respect to the Notes, to the extent that payment would be required by the laws of a Relevant Taxing Jurisdiction to be included in the income, for tax purposes, of a beneficiary or settlor with respect to the fiduciary, a member of that partnership, an interest holder in that limited liability company or a beneficial owner who would not have been entitled to the Additional Amounts had it been the Holder of the Notes.

The Company, the relevant Subsidiary Guarantor or the relevant Successor, as the case may be, will (i) make such withholding or deduction as is required by applicable law and (ii) remit the full amount withheld or deducted to the relevant taxing authority in accordance with applicable law.

At least 30 calendar days prior to each date on which any payment under or with respect to the Notes is due and payable, if the Company, any Subsidiary Guarantor or a Successor will be obligated to pay Additional Amounts with respect to such payment, the Company, the relevant Subsidiary Guarantor or the relevant Successor (as the case may be) will deliver to the Trustee an officers certificate stating that such Additional Amounts will be payable and the amounts so payable and will set forth such other information necessary to enable the Trustee to pay such Additional Amounts to Holders on the payment date (unless such obligation to pay Additional Amounts arises after the 30th day prior to the date on which payment under or with respect to the Notes is due and payable, in which case such officers certificate shall be delivered promptly thereafter). The Company, the relevant Subsidiary Guarantor or the relevant Successor, as the case may be, will promptly publish a notice in accordance with the notice provisions set forth in the Indenture stating that such Additional Amounts will be payable and describing the obligation to pay such amounts.

Upon written request, the Company, the relevant Subsidiary Guarantor or the relevant Successor, as the case may be, will furnish to the Trustee or to a Holder of the Notes copies of tax receipts evidencing the payment of any Taxes by the Company, such Guarantor or such Successor in such form as provided in the normal course by the taxing authority imposing such Taxes and as is reasonably available to the Company, such Subsidiary Guarantor or such Successor. If, notwithstanding the efforts of the Company, such Subsidiary Guarantor or such Successor to obtain such receipts, the same are not obtainable, the Company, such Subsidiary Guarantor or such Successor will provide the Trustee or such Holder with other evidence reasonably satisfactory to the Trustee or the Holder.

In addition, the Company, any Subsidiary Guarantor and any Successor, as the case may be, will pay any present or future stamp, issue, registration, court, documentation, excise or property taxes or other similar taxes, charges and duties, including interest and penalties with respect thereto, imposed by or in any Relevant Taxing Jurisdiction in respect of the execution, issue, enforcement or delivery of the Notes or any other document or instrument referred to thereunder (other than on or in connection with a transfer of the Notes other than the initial resale by the underwriters).

Whenever the Indenture, the Notes or this Description of Notes refers to, in any context, the payment of principal, premium, if any, interest or any other amount payable under or with respect to any Note or with respect to any Guarantee, such reference includes the payment of Additional Amounts, if applicable.

Change of Control

The Indenture provides that, following the occurrence of any Change of Control, unless the Company has exercised its right to redeem all of the Notes, the Company must offer to purchase all outstanding Notes at a purchase price equal to 101% of the aggregate principal amount of the Notes, plus accrued and unpaid interest to the date of purchase.

Within 15 days after any Change of Control, the Company will mail or cause to be mailed to all Holders on the date of the Change of Control a Notice (the Change of Control Notice) of the occurrence of such Change of Control and of the Holders rights arising as a result thereof. The Change of Control Notice shall state, among other things:

(1) that the change of control offer is being made pursuant to this covenant;

(2) the purchase price and the change of control payment date;

(3) that any Note not tendered will continue to accrue interest;

(4) that any Note accepted for payment pursuant to the change of control offer shall cease to accrue interest on the change of control payment date; and

(5) the instructions, consistent with the covenant described hereunder, that a Holder must follow in order to have such Holder s Notes purchased.

The change of control offer will be deemed to have commenced upon mailing of a notice pursuant to the Indenture and will terminate 20 business days after its commencement, unless a longer offering period is required by law. Promptly after the termination of the change of control offer, the Company will purchase and mail or deliver payment for all Notes tendered in response to the change of control offer.

On the change of control payment date, the Company will, to the extent lawful, (a) accept for payment Notes or portions thereof tendered pursuant to the change of control offer, (b) deposit with a paying agent an amount equal to the change of control payment in respect of all Notes or portions thereof so tendered and (c) deliver to the Trustee the Notes so accepted together with an officers certificate stating the Notes or portions thereof tendered to the Company. The paying agent will promptly mail or deliver to each Holder of Notes so accepted payment in an amount equal to the purchase price for such Notes, and the Trustee will promptly authenticate and mail or deliver to each Holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any, provided that each such new Note will be in a principal amount of 50,000 or in any integral multiple of 1,000 in excess thereof.

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The Company will comply with Section 14 of the Exchange Act and the provisions of Regulation 14E and any other tender offer rules under the Exchange Act and any other U.S. federal and state securities laws, rules and regulations and other jurisdictions laws which may then be applicable to any change of control offer.

The Change of Control purchase feature of the Notes may in certain circumstances make more difficult or discourage a sale or takeover of the Company. The change of control purchase feature is a result of negotiations between the Company and the underwriters. The Company has no present intention to engage in a transaction involving a Change of Control, although it is possible that it could decide to do so in the future. Subject to the limitations discussed below, the Company could, in the future, enter into certain transactions, including acquisitions, refinancings or other recapitalizations, that would not constitute a Change of Control under the Indenture, but that could increase the amount of indebtedness outstanding at such time or otherwise affect the Company s capital structure or credit ratings. Restrictions on the Company s ability to incur additional Indebtedness are contained in the covenants described under Certain Covenants Limitation on Liens and Limitation on Sale/Leaseback Transactions. Under the Indenture, such restrictions can only be waived with the consent of the Holders of a majority in principal amount of the Notes then outstanding. Except for the limitations contained in such covenants, however, the Indenture does not contain any covenants or provisions that may afford Holders of the Notes protection in the event of a highly leveraged transaction.

Future indebtedness that the Company may incur may contain prohibitions on the occurrence of certain events that would constitute a Change of Control or require the repurchase of such indebtedness upon a Change of Control. Moreover, the exercise by the Holders of their right to require the Company to repurchase the Notes could cause a default under such indebtedness, even if the Change of Control itself does not, due to the financial effect of such repurchase on the Company. Finally, the Company s ability to pay cash to the Holders of Notes following the occurrence of a Change of Control may be limited by the Company s then existing financial resources. There can be no assurance that sufficient funds will be available when necessary to make any required repurchases.

The provisions under the Indenture relative to the Company s obligation to make an offer to repurchase the Notes as a result of a Change of Control may be waived or modified with the written consent of the Holders of a majority in principal amount of the Notes.

Certain Covenants

The following restrictive covenants will be applicable to the Company and its Subsidiaries.

Limitation on Liens. The Company will not, and will not permit any Subsidiary to, create, incur or assume any Indebtedness secured by any Liens (other than Permitted Liens) upon any of the properties of the Company or any Subsidiary, unless the Notes or a Guarantee is equally and ratably secured; *provided* that if such Indebtedness is expressly subordinated to the Notes or a Guarantee, the Lien securing such Indebtedness will be subordinated and junior to the Lien securing the Notes or such Guarantee.

Limitation on Sale/Leaseback Transactions. The Company will not, and will not permit any Subsidiary to, enter into any Sale/Leaseback Transaction with any Person (other than the Company or any other Subsidiary) unless:

(1) the Company or such Subsidiary would be entitled to incur secured Indebtedness, in a principal amount equal to the Attributable Indebtedness with respect to such Sale/Leaseback Transaction in accordance with the covenant captioned Limitation on Liens ; or

(2) the Company or such Subsidiary receives proceeds from such Sale/Leaseback Transaction at least equal to the fair market value thereof (as determined in good faith by the Company s Board of

Directors, whose determination in good faith, evidenced by a resolution of such Board, shall be conclusive) and such proceeds are applied in accordance with the following two paragraphs:

The Company may apply Net Available Proceeds from such Sale/Leaseback Transaction, within 365 days following the receipt of Net Available Proceeds from the Sale/Leaseback Transaction, to:

(1) the repayment of Indebtedness of the Company or a Subsidiary under Credit Facilities or other Senior Indebtedness, including any mandatory redemption or repurchase or make-whole redemption of the Existing Notes or the Notes;

(2) make an Investment in assets used in the Oil and Gas Business; or

(3) develop by drilling the Company s oil and gas reserves.

If, upon completion of the 365-day period, any portion of the Net Available Proceeds shall not have been applied by the Company as described in clauses (1), (2) or (3) in the immediately preceding paragraph and such remaining Net Available Proceeds, together with any remaining net cash proceeds from any prior Sale/Leaseback Transaction (such aggregate constituting Excess Proceeds), exceed $40 million, then the Company will be obligated to make an offer (the Net Proceeds Offer) to purchase the Notes and any other Senior Indebtedness in respect of which such an offer to purchase is also required to be made concurrently with the Net Proceeds Offer having an aggregate principal amount (or, with respect to the Notes, an equivalent amount in dollars based on the Federal Reserve Bank of New York noon buying rate of euro on the second business day preceding such offer) equal to the Excess Proceeds (such purchase to be made on a pro rata basis if the amount available for such repurchase is less than the principal amount of the Notes and other such Senior Indebtedness tendered in such Net Proceeds Offer) at a purchase price of 100% of the principal amount thereof plus accrued interest to the date of repurchase. Upon the completion of the Net Proceeds Offer, the amount of Excess Proceeds will be reset to zero.

Within 15 days after the Company becomes obligated to make a Net Proceeds Offer (a Net Proceeds Offer Triggering Event), the Company will mail or cause to be mailed to all Holders on the date of the Net Proceeds Offer Triggering Event a notice (the Offer Notice) of the occurrence of such Net Proceeds Offer Triggering Event and of the Holders rights arising as a result thereof. The Offer Notice shall state, among other things:

(1) that the offer is being made pursuant to this covenant;

(2) that any Note not tendered will continue to accrue interest;

(3) that any Note accepted for payment pursuant to the offer shall cease to accrue interest on the payment date; and

(4) the instructions, consistent with this covenant, that a Holder must follow in order to have such Holder s Notes purchased.

The Net Proceeds Offer will be deemed to have commenced upon mailing of the Offer Notice and will terminate 20 business days after its commencement, unless a longer offering period is required by law. Promptly after the termination of the offer, the Company will purchase and mail or deliver payment for all Notes tendered in response to the offer.

On the payment date, the Company will, to the extent lawful, (a) accept for payment Notes or portions thereof tendered pursuant to the Net Proceeds Offer, (b) deposit with a paying agent an amount equal to the payment in respect of all Notes or portions thereof so tendered and (c) deliver to the Trustee the Notes so accepted together with an officers certificate stating the Notes or portions thereof tendered to the Company. The paying agent will promptly mail or deliver to each Holder of Notes so accepted

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payment in an amount equal to the purchase price for such Notes, and the Trustee will promptly authenticate and mail or deliver to each Holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any, *provided* that each such new Note will be in a principal amount of 50,000 or in any integral multiple of 1,000 in excess thereof.

The Company will comply with Section 14 of the Exchange Act and the provisions of Regulation 14E and any other tender offer rules under the Exchange Act and any other U.S. federal and state securities laws, rules and regulations and any laws of other jurisdictions which may then be applicable to any Net Proceeds Offer.

During the period between any Sale/Leaseback Transaction and the application of the Net Available Proceeds therefrom in accordance with this covenant, all Net Available Proceeds shall be maintained in a segregated account and shall be invested in Permitted Financial Investments.

Limitations on Mergers and Consolidations. The Company will not consolidate or merge with or into any Person, or sell, convey, lease or otherwise dispose of all or substantially all of its assets to any Person, unless:

(1) the Person formed by or surviving such consolidation or merger (if other than the Company), or to which such sale, lease, conveyance or other disposition shall be made (collectively, the Successor), is a corporation, limited liability company or limited partnership organized and existing under the laws of the United States or any state thereof or the District of Columbia, or Canada or any province thereof, and the Successor assumes by supplemental indenture all of the obligations of the Company under the Indenture and under the Notes; *provided,* that unless the Successor is a corporation, a corporate co-issuer of the Notes will be added to the Indenture by such supplemental indenture; and

(2) immediately before and after giving effect to such transaction, no Default or Event of Default exists.

SEC Reports. Notwithstanding that the Company may not be required to remain subject to the reporting requirements of Section 13 or 15(d) of the Exchange Act, the Company will file with the SEC and provide the Holders with annual reports and such information, documents and other reports specified in Sections 13 and 15(d) of the Exchange Act.

Certain Definitions

The following is a summary of certain defined terms used in the Indenture. Reference is made to the Indenture for the full definition of all such terms and for the definitions of capitalized terms used in this prospectus and not defined below.

Adjusted Consolidated Net Tangible Assets or *ACNTA* means, without duplication, as of the date of determination, (a) the sum of

(1)

discounted future net revenue from proved oil and gas reserves of the Company and its Subsidiaries calculated in accordance with SEC guidelines before any U.S. state or federal income taxes, as estimated by petroleum engineers (which may include the Company s internal engineers) in a reserve report prepared as of the end of the Company s most recently completed fiscal year, as increased by, as of the date of determination, the discounted future net revenue of (A) estimated proved oil and gas reserves of the Company and its Subsidiaries attributable to any acquisition consummated since the date of such year-end reserve report and (B) estimated proved oil and gas reserves of the Company and its Subsidiaries attributable to extensions, discoveries and other additions and upward revisions of estimates of proved oil and gas reserves due to exploration, development or exploitation, production or other activities conducted or otherwise occurring since the date of such year-end

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reserve report which, in the case of sub-clauses (A) and (B), would, in accordance with standard industry practice, result in such increases as calculated in accordance with SEC guidelines (utilizing the prices utilized in such year-end reserve report), and decreased by, as of the date of determination, the discounted future net revenue of (C) estimated proved oil and gas reserves of the Company and its Subsidiaries produced or disposed of since the date of such year-end reserve report and (D) reductions in the estimated oil and gas reserves of the Company and its Subsidiaries since the date of such year-end reserve report attributable to downward revisions of estimates of proved oil and gas reserves due to exploration, development or exploitation, production or other activities conducted or otherwise occurring since the date of such year-end reserve report which, in the case of sub-clauses (C) and (D) would, in accordance with standard industry practice, result in such decreases as calculated in accordance with SEC guidelines (utilizing the prices utilized in such year-end reserve report); *provided* that, in the case of each of the determinations made pursuant to clauses (A) through (D), such increases and decreases shall be as estimated by the Company s engineers,

(2) the capitalized costs that are attributable to oil and gas properties of the Company and its Subsidiaries to which no proved oil and gas reserves are attributable, based on the Company s books and records as of a date no earlier than the date of the Company s latest annual or quarterly financial statements,

(3) the Net Working Capital on a date no earlier than the date of the Company s latest annual or quarterly financial statements and

(4) the greater of (A) the net book value on a date no earlier than the date of the Company s latest annual or quarterly financial statements and (B) the appraised value, as estimated by independent appraisers, of other tangible assets (including Investments in unconsolidated Subsidiaries) of the Company and its Subsidiaries, as of a date no earlier than the date of the Company s latest audited financial statements,

minus (b) the sum of

(1) minority interests,

(2) any gas balancing liabilities of the Company and its Subsidiaries reflected as a long-term liability in the Company s latest annual or quarterly financial statements,

(3) the discounted future net revenue, calculated in accordance with SEC guidelines (utilizing the prices utilized in the Company s year-end reserve report), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of the Company and its Subsidiaries with respect to Volumetric Production Payments on the schedules specified with respect thereto,

(4) the discounted future net revenue, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production included in determining the discounted future net revenue specified in (a)(1) above (utilizing the same prices utilized in the Company s year-end reserve report), would be necessary to fully satisfy the payment obligations of the Company and its Subsidiaries with respect to Dollar-Denominated Production Payments on the schedules specified with respect thereto and

(5) the discounted future net revenue, calculated in accordance with SEC guidelines (utilizing the same prices utilized in the Company s year-end reserve report), attributable to reserves subject to participation interests, overriding royalty interests or other interests of third parties, pursuant to participation, partnership, vendor financing or other agreements then in effect, or which otherwise are required to be delivered to third parties.

If the Company changes its method of accounting from the full cost method to the successful efforts method or a similar method of accounting, ACNTA will continue to be calculated as if the Company were still using the full cost method of accounting.

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Affiliate of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For the purposes of this definition, control when used with respect to any specified Person means the power to direct the management and policies of such Person directly or indirectly, whether through the ownership of voting stock, by contract or otherwise; and the terms controlling and controlled have meanings correlative to the foregoing.

Attributable Indebtedness means, with respect to any particular lease under which any Person is at the time liable and at any date as of which the amount thereof is to be determined, the present value of the total net amount of rent required to be paid by such Person under the lease during the primary term thereof, without giving effect to any renewals at the option of the lessee, discounted from the respective due dates thereof to such date at the rate of interest per annum implicit in the terms of the lease. As used in the preceding sentence, the net amount of rent under any lease for any such period shall mean the sum of rental and other payments required to be paid with respect to such period by the lessee thereunder excluding any amounts required to be paid by such lessee on account of maintenance and repairs, insurance, taxes, assessments, water rates or similar charges. In the case of any lease which is terminable by the lessee upon payment of a penalty, such net amount of rent shall also include the amount of such penalty, but no rent shall be considered as required to be paid under such lease subsequent to the first date upon which it may be so terminated.

Average Life means, as of the date of determination, with respect to any Indebtedness, the quotient obtained by dividing (a) the product of (x) the number of years from such date to the date of each successive scheduled principal payment of such Indebtedness multiplied by (y) the amount of such principal payment by (b) the sum of all such principal payments.

Capital Stock means, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated) of corporate stock or partnership or limited liability company interests and any and all warrants, options and rights with respect thereto (whether or not currently exercisable), including each class of common stock and preferred stock of such Person.

Capitalized Lease Obligations of any Person means the obligations of such Person to pay rent or other amounts under a lease of property, real or personal, that is required to be capitalized for financial reporting purposes in accordance with GAAP, and the amount of such obligations shall be the capitalized amount thereof determined in accordance with GAAP.

Change of Control means the occurrence of any of the following:

(1) the sale, lease or transfer, in one or a series of related transactions, of all or substantially all of the Company s assets to any Person or group (as such term is used in Section 13(d)(3) of the Exchange Act), other than to Permitted Holders;

(2) the adoption of a plan relating to the liquidation or dissolution of the Company;

(3) the acquisition, directly or indirectly, by any Person or group (as such term is used in Section 13(d)(3) of the Exchange Act), other than Permitted Holders, of beneficial ownership (as defined in Rule 13d-3 under the Exchange Act, except that such Person shall be deemed to have beneficial ownership of all shares that any such Person has the right to acquire, whether such right is exercisable immediately or only after passage of time) of more than 50% of the aggregate voting power of the Voting Stock of the Company; provided, however, that the Permitted Holders beneficially own (as defined in Rules 13d-3 and 13d-5 under the Exchange Act), directly or indirectly, in the aggregate a lesser percentage of the total voting power of the

Voting Stock of the Company than such other Person and do not have the right or ability by voting power, contract or otherwise to elect or designate for election a majority of the Board of Directors of the Company (for the purposes of this definition, such other Person shall be deemed to beneficially own any Voting Stock of a specified corporation held by a parent corporation, if such other Person is the beneficial owner (as defined above), directly or indirectly, of more than 35% of the voting power of the Voting Stock of such parent corporation and the Permitted Holders beneficially own (as defined in this proviso), directly or indirectly, in the aggregate a lesser percentage of the voting power of the Voting Stock of such parent corporation and do not have the right or ability by voting power, contract or otherwise to elect or designate for election a majority of the Board of Directors of such parent corporation); or

(4) during any period of two consecutive years, individuals who at the beginning of such period constituted the Board of Directors of the Company (together with any new directors whose election by such Board of Directors or whose nomination for election by the shareholders of the Company was approved by a vote of 66 $^{2}/3$% of the directors of the Company then still in office who were either directors at the beginning of such period or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of the Board of Directors of the Company then in office.

Credit Facilities means, one or more debt facilities (including, without limitation, the Company s existing credit facility) or commercial paper facilities, in each case with banks, investment banks, insurance companies, mutual funds and/or other institutional lenders providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from (or sell receivables to) such lenders against such receivables) or letters of credit, in each case, as amended, extended, restated, renewed, refunded, replaced or refinanced (in each case with Credit Facilities), supplemented or otherwise modified (in whole or in part and without limitation as to amount, terms, conditions, covenants and other provisions) from time to time.

Currency Hedge Obligations means, at any time as to the Company and its Subsidiaries, the obligations of any such Person at such time that were incurred in the ordinary course of business pursuant to any non-dollar currency exchange agreement, option or futures contract or other similar agreement or arrangement designed to protect against or manage such Person s or any of its Subsidiaries exposure to fluctuations in non-dollar currency exchange rates.

Default means any event which is, or after notice of passage of time would be, an Event of Default.

De Minimis Guaranteed Amount means a principal amount of Indebtedness that does not exceed $5 million.

Disqualified Stock means any Capital Stock of the Company or any Subsidiary of the Company which, by its terms (or by the terms of any security into which it is convertible or for which it is exchangeable), or upon the happening of any event or with the passage of time, matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or is redeemable at the option of the holder thereof, in whole or in part, on or prior to the Maturity Date or which is exchangeable or convertible into debt securities of the Company or any Subsidiary of the Company, except to the extent that such exchange or conversion rights cannot be exercised prior to the Maturity Date.

Dollar-Denominated Production Payments mean production payment obligations recorded as liabilities in accordance with GAAP, together with all undertakings and obligations in connection therewith.

European Government Obligations means (1) securities that are direct obligations of the Federal Republic of Germany for the payment of which its full faith and credit is pledged or (2) obligations of a person controlled or supervised by and acting as an agency or instrumentality of the Federal Republic of Germany, the payment of which is unconditionally guaranteed as a full faith and credit obligation by the Federal Republic of Germany, which, in either case under clauses (1) or (2) are not callable or redeemable at the option of the issuer thereof.

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Exchange Act means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC thereunder.

Existing Notes means the Company s outstanding (a) 7.5% Senior Notes due 2013, (b) 7.625% Senior Notes due 2013, (c) 7.5% Senior Notes due 2014, (d) 7% Senior Notes due 2014, (e) 7.75% Senior Notes due 2015, (f) 6.375% Senior Notes due 2015, (g) 6.875% Senior Notes due 2016, (h) 6.625% Senior Notes due 2016, (i) 6.5% Senior Notes due 2017, (j) 6.25% Senior Notes due 2018, (k) 6.875% Senior Notes due 2020 and (l) 2.75% Contingent Convertible Senior Notes due 2035.

GAAP means generally accepted accounting principles as in effect in the United States of America as of the Issue Date.

Guarantee means, individually and collectively, the guarantees given by the Subsidiary Guarantors pursuant to Article Ten of the Indenture.

Holder means a Person in whose name a Note is registered on the registrar s books, which will initially be the nominee for the common depository of Euroclear or Clearstream, as applicable.

Indebtedness means, without duplication, with respect to any Person,

(a) all obligations of such Person

(1) in respect of borrowed money (whether or not the recourse of the lender is to the whole of the assets of such Person or only to a portion thereof),

(2) evidenced by bonds, notes, debentures or similar instruments,

(3) representing the balance deferred and unpaid of the purchase price of any property or services (other than accounts payable or other obligations arising in the ordinary course of business),

(4) evidenced by bankers acceptances or similar instruments issued or accepted by banks,

(5) for the payment of money relating to a Capitalized Lease Obligation, or

(6) evidenced by a letter of credit or a reimbursement obligation of such Person with respect to any letter of credit;

(b) all net obligations of such Person under Interest Rate Hedging Agreements, Oil and Gas Hedging Contracts, and Currency Hedge Obligations, except to the extent such net obligations are taken into account in the determination of future net revenues from proved oil and gas reserves for purposes of the calculation of Adjusted Consolidated Net Tangible Assets;

(c) all liabilities of others of the kind described in the preceding clauses (a) or (b) that such Person has guaranteed or that are otherwise its legal liability (including, with respect to any Production Payment, any warranties or guaranties of production or payment by such Person with respect to such Production Payment but excluding other contractual obligations of such Person with respect to such Production Payment);

(d) Indebtedness (as otherwise defined in this definition) of another Person secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person, the amount of such obligations being deemed to be the lesser of

(1) the full amount of such obligations so secured and

(2) the fair market value of such asset, as determined in good faith by the Board of Directors of such Person, which determination shall be evidenced by a resolution of such Board;

(e) with respect to such Person, the liquidation preference or any mandatory redemption payment obligations in respect of Disqualified Stock;

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(f) the aggregate preference in respect of amounts payable on the issued and outstanding shares of preferred stock of any of such Person s Subsidiaries in the event of any voluntary or involuntary liquidation, dissolution or winding up (excluding any such preference attributable to such shares of preferred stock that are owned by such Person or any of its Subsidiaries; *provided,* that if such Person is the Company, such exclusion shall be for such preference attributable to such shares of preferred stock that are owned by the Company or any of its Subsidiaries); and

(g) any and all deferrals, renewals, extensions, refinancings and refundings (whether direct or indirect) of, or amendments, modifications or supplements to, any liability of the kind described in any of the preceding clauses (a), (b), (c), (d), (e) or (f) or this clause (g), whether or not between or among the same parties.

Subject to clause (c) of the preceding sentence, neither Dollar-Denominated Production Payments nor Volumetric Production Payments shall be deemed to be Indebtedness.

Interest Rate Hedging Agreements means, with respect to the Company and its Subsidiaries, the obligations of such Persons under (a) interest rate swap agreements, interest rate cap agreements and interest rate collar agreements and (b) other agreements or arrangements designed to protect any such Person or any of its Subsidiaries against fluctuations in interest rates.

Investment of any Person means (a) all investments by such Person in any other Person in the form of loans, advances or capital contributions, (b) all guarantees of Indebtedness or other obligations of any other Person by such Person, (c) all purchases (or other acquisitions for consideration) by such Person of assets, Indebtedness, Capital Stock or other securities of any other Person and (d) all other items that would be classified as investments (including, without limitation, purchases of assets outside the ordinary course of business) or advances on a balance sheet of such Person prepared in accordance with GAAP.

Issue Date means the first date on which the Notes are originally issued, December 6, 2006.

Lien means, with respect to any Person, any mortgage, pledge, lien, encumbrance, easement, restriction, covenant, right-of-way, charge or adverse claim affecting title or resulting in an encumbrance against real or personal property of such Person, or a security interest of any kind (including any conditional sale or other title retention agreement, any lease in the nature thereof, any option, right of first refusal or other similar agreement to sell, in each case securing obligations of such Person and any filing of or agreement to give any financing statement under the Uniform Commercial Code (or equivalent statute or statutes) of any jurisdiction).

Make-Whole Amount with respect to a Note means an amount equal to the excess, if any, of (a) the present value of the remaining interest, premium and principal payments due on such Note (excluding any portion of such payments of interest accrued as of the redemption date) as if such Note were redeemed on the Maturity Date, computed using a discount rate equal to the Bund Rate plus 50 basis points, over (b) the outstanding principal amount of such Note. Bund Rate with respect to a Note means the yield to maturity (calculated on a semi-annual bond equivalent basis) at the time of the computation of direct obligations of the Federal Republic of Germany (*Bunds* or *Bundesanleihe*) with a constant maturity (as compiled by and published in the most recent financial statistics that have become publicly available at least two business days prior to the date of the redemption notice or, if such financial statistics are no longer published, any publicly available source of similar market data) most nearly equal to the then remaining maturity of such Note assuming that such Note will be redeemed on the Maturity Date; *provided, however,* that if the Make-Whole Average Life of a Note is not equal to the constant maturity of a direct obligation of the Federal Republic of Germany for which a weekly average yield is given, the Bund Rate shall be obtained by linear interpolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of direct obligations of the Federal Republic of Germany for which

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such yields are given, except that if the Make-Whole Average Life of such Note is less than one year, the weekly average yield on actually traded direct obligations of the Federal Republic of Germany adjusted to a constant maturity of one year shall be used.
Make-Whole Average Life means, with respect to a Note, the number of years (calculated to the nearest one-twelfth of a year) between the date of redemption of such Note and the Maturity Date.

Make-Whole Price means the sum of the outstanding principal amount of the Notes to be redeemed plus the Make-Whole Amount of such Notes.

Maturity Date means January 15, 2017.

Moody s means Moody s Investors Service, Inc. or any successor to the rating agency business thereof.

Net Available Proceeds means, with respect to any Sale/Leaseback Transaction of any Person, cash proceeds received (including any cash proceeds received by way of deferred payment of principal pursuant to a note or installment receivable or otherwise, but only as and when received, and excluding any other consideration until such time as such consideration is converted into cash) therefrom, in each case net of all legal, title and recording tax expenses, commissions and other fees and expenses incurred, and all U.S. federal, state or local taxes or taxes in other jurisdictions required to be accrued as a liability as a consequence of such Sale/Leaseback Transaction, and in each case net of all Indebtedness which is secured by such assets, in accordance with the terms of any Lien upon or with respect to such assets, or which must, by its terms or in order to obtain a necessary consent to such Sale/Leaseback Transaction or by applicable law, be repaid out of the proceeds from such Sale/Leaseback Transaction and which is actually so repaid.

Net Working Capital means (a) all current assets of the Company and its Subsidiaries, minus (b) all current liabilities of the Company and its Subsidiaries, except current liabilities included in Indebtedness.

Oil and Gas Business means the business of the exploration for, and exploitation, development, production, processing (but not refining), marketing, storage and transportation of, hydrocarbons, and other related energy and natural resource businesses (including oil and gas services businesses related to the foregoing).

Oil and Gas Hedging Contracts means any oil and gas purchase or hedging agreement, and other agreement or arrangement, in each case, that is designed to provide protection against price fluctuations of oil, gas or other commodities.

Permitted Company Refinancing Indebtedness means Indebtedness of the Company, the net proceeds of which are used to renew, extend, refinance, refund or repurchase outstanding Indebtedness of the Company, *provided* that

(1) if the Indebtedness (including the Notes) being renewed, extended, refinanced, refunded or repurchased is pari passu with or subordinated in right of payment to the Notes, then such Indebtedness is pari passu or subordinated in right of payment to, as

the case may be, the Notes at least to the same extent as the Indebtedness being renewed, extended, refinanced, refunded or repurchased,

(2) such Indebtedness is scheduled to mature no earlier than the Indebtedness being renewed, extended, refinanced, refunded or repurchased, and

(3) such Indebtedness has an Average Life at the time such Indebtedness is incurred that is equal to or greater than the Average Life of the Indebtedness being renewed, extended, refinanced, refunded or repurchased;

provided, further, that such Indebtedness (to the extent that such Indebtedness constitutes Permitted Company Refinancing Indebtedness) is in an aggregate principal amount (or, if such Indebtedness is

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issued at a price less than the principal amount thereof, the aggregate amount of gross proceeds therefrom is) not in excess of the aggregate principal amount then outstanding of the Indebtedness being renewed, extended, refinanced, refunded or repurchased (or if the Indebtedness being renewed, extended, refinanced, refunded or repurchased was issued at a price less than the principal amount thereof, then not in excess of the amount of liability in respect thereof determined in accordance with GAAP).

Permitted Financial Investments means the following kinds of instruments if, in the case of instruments referred to in clauses (1)-(4) below, on the date of purchase or other acquisition of any such instrument by the Company or any Subsidiary, the remaining term to maturity is not more than one year:

(1) readily marketable obligations issued or unconditionally guaranteed as to principal of and interest thereon by the United States of America or by any agency or authority controlled or supervised by and acting as an instrumentality of the United States of America;

(2) repurchase obligations for instruments of the type described in clause (1) for which delivery of the instrument is made against payment;

(3) obligations (including, but not limited to, demand or time deposits, bankers acceptances and certificates of deposit) issued by a depositary institution or trust company incorporated or doing business under the laws of the United States of America, any state thereof or the District of Columbia or a branch or subsidiary of any such depositary institution or trust company operating outside the United States, *provided*, that such depositary institution or trust company has, at the time of the Company s or such Subsidiary s investment therein or contractual commitment providing for such investment, capital surplus or undivided profits (as of the date of such institution s most recently published financial statements) in excess of $500,000,000;

(4) commercial paper issued by any corporation, if such commercial paper has, at the time of the Company s or any Subsidiary s investment therein or contractual commitment providing for such investment, credit ratings of A-1 (or higher) by S&P and P-1 (or higher) by Moody s; and

(5) money market mutual or similar funds having assets in excess of $500,000,000.

Permitted Holders means Aubrey K. McClendon and his Affiliates.

Permitted Liens means

(1) Liens existing on the Issue Date;

(2) Liens securing Indebtedness under Credit Facilities;

(3) Liens now or hereafter securing any obligations under Interest Rate Hedging Agreements so long as the related Indebtedness (a) constitutes the Existing Notes or the Notes (or any Permitted Company Refinancing Indebtedness in respect thereof) or (b) is, or is permitted to be under the Indenture, secured by a Lien on the same property securing such interest rate hedging obligations;

(4) Liens securing Permitted Company Refinancing Indebtedness or Permitted Subsidiary Refinancing Indebtedness; *provided,* that such Liens extend to or cover only the property or assets currently securing the Indebtedness being refinanced and that the Indebtedness being refinanced was not incurred under the Credit Facilities;

(5) Liens for taxes, assessments and governmental charges not yet delinquent or being contested in good faith and for which adequate reserves have been established to the extent required by GAAP;

(6) mechanics , worker s, materialmen s, operators or similar Liens arising in the ordinary course of business;

(7) Liens in connection with worker s compensation, unemployment insurance or other social security, old age pension or public liability obligations;

(8) Liens, deposits or pledges to secure the performance of bids, tenders, contracts (other than contracts for the payment of money), leases, public or statutory obligations, surety, stay, appeal, indemnity, performance or other similar bonds, or other similar obligations arising in the ordinary course of business;

(9) survey exceptions, encumbrances, easements or reservations of, or rights of others for, rights of way, zoning or other restrictions as to the use of real properties, and minor defects in title which, in the case of any of the foregoing, were not incurred or created to secure the payment of borrowed money or the deferred purchase price of property or services, and in the aggregate do not materially adversely affect the value of such properties or materially impair use for the purposes of which such properties are held by the Company or any Subsidiaries;

(10) Liens on, or related to, properties to secure all or part of the costs incurred in the ordinary course of business of exploration, drilling, development or operation thereof;

(11) Liens on pipeline or pipeline facilities which arise out of operation of law;

(12) judgment and attachment Liens not giving rise to an Event of Default or Liens created by or existing from any litigation or legal proceeding that are currently being contested in good faith by appropriate proceedings and for which adequate reserves have been made;

(13) (a) Liens upon any property of any Person existing at the time of acquisition thereof by the Company or a Subsidiary, (b) Liens upon any property of a Person existing at the time such Person is merged or consolidated with the Company or any Subsidiary or existing at the time of the sale or transfer of any such property of such Person to the Company or any Subsidiary, or (c) Liens upon any property of a Person existing at the time such Person becomes a Subsidiary; *provided*, that in each case such Lien has not been created in contemplation of such sale, merger, consolidation, transfer or acquisition, and *provided* that in each such case no such Lien shall extend to or cover any property of the Company or any Subsidiary other than the property being acquired and improvements thereon;

(14) Liens on deposits to secure public or statutory obligations or in lieu of surety or appeal bonds entered into in the ordinary course of business;

(15) Liens in favor of collecting or payor banks having a right of setoff, revocation, refund or chargeback with respect to money or instruments of the Company or any Subsidiary on deposit with or in possession of such bank;

(16) purchase money security interests granted in connection with the acquisition of assets in the ordinary course of business and consistent with past practices, *provided*, that (A) such Liens attach only to the property so acquired with the purchase money indebtedness secured thereby and (B) such Liens secure only Indebtedness that is not in excess of 100% of the purchase price of such assets;

(17) Liens reserved in oil and gas mineral leases for bonus or rental payments and for compliance with the terms of such leases;

(18) Liens arising under partnership agreements, oil and gas leases, farm-out agreements, division orders, contracts for the sale, purchase, exchange, transportation or processing (but not refining) of oil, gas or other hydrocarbons, unitization and pooling declarations and agreements, development agreements, operating agreements, area of mutual interest agreements, and other similar agreements which are customary in the Oil and Gas Business;

(19)

Liens securing obligations of the Company or any of its Subsidiaries under Currency Hedge Obligations or Oil and Gas Hedging Contracts;

(20) Liens to secure Dollar-Denominated Production Payments and Volumetric Production Payments; and

(21) Liens securing other Indebtedness in an aggregate principal amount which, together with all other Indebtedness outstanding on the date of such incurrence and secured by Liens pursuant to this clause (21), does not exceed 15% of Adjusted Consolidated Tangible Net Assets.

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Permitted Subsidiary Refinancing Indebtedness means Indebtedness of any Subsidiary, the net proceeds of which are used to renew, extend, refinance, refund or repurchase outstanding Indebtedness of such Subsidiary, *provided* that

(1) if the Indebtedness (including the Guarantees) being renewed, extended, refinanced, refunded or repurchased is pari passu with or subordinated in right of payment to the Guarantees, then such Indebtedness is pari passu with or subordinated in right of payment to, as the case may be, the Guarantees at least to the same extent as the Indebtedness being renewed, extended, refinanced, refunded or repurchased,

(2) such Indebtedness is scheduled to mature no earlier than the Indebtedness being renewed, extended, refinanced, refunded or repurchased, and

(3) such Indebtedness has an Average Life at the time such Indebtedness is incurred that is equal to or greater than the Average Life of the Indebtedness being renewed, extended, refinanced, refunded or repurchased;

provided, further, that such Indebtedness (to the extent that such Indebtedness constitutes Permitted Subsidiary Refinancing Indebtedness) is in an aggregate principal amount (or, if such Indebtedness is issued at a price less than the principal amount thereof, the aggregate amount of gross proceeds therefrom is) not in excess of the aggregate principal amount then outstanding of the Indebtedness being renewed, extended, refinanced, refunded or repurchased (or if the Indebtedness being renewed, extended, refinanced, refunded or repurchased was issued at a price less than the principal amount thereof, then not in excess of the amount of liability in respect thereof determined in accordance with GAAP).

Person means any individual, corporation, partnership, joint venture, trust, estate, unincorporated organization or government or any agency or political subdivision thereof.

Production Payments means, collectively, Dollar-Denominated Production Payments and Volumetric Production Payments.

S&P refers to Standard & Poor s Ratings Services, a division of The McGraw-Hill Companies, Inc., or any successor to the rating agency business thereof.

Sale/Leaseback Transaction means with respect to the Company or any of its Subsidiaries, any arrangement with any Person providing for the leasing by the Company or any of its Subsidiaries of any principal property, acquired or placed into service more than 180 days prior to such arrangement, whereby such property has been or is to be sold or transferred by the Company or any of its Subsidiaries to such Person.

Senior Indebtedness means any Indebtedness of the Company or a Subsidiary Guarantor (whether outstanding on the Issue Date or thereafter incurred), unless such Indebtedness is contractually subordinate or junior in right of payment of principal, premium and interest to the Notes or the Guarantees, respectively.

Subordinated Indebtedness of a Subsidiary Guarantor means any Indebtedness of such Subsidiary Guarantor, whether outstanding on the Issue Date or thereafter created, incurred or assumed, which is contractually subordinate or junior in right of payment of principal, premium and interest to the Guarantees.

Subordinated Indebtedness of the Company means any Indebtedness of the Company, whether outstanding on the Issue Date or thereafter incurred, which is contractually subordinate or junior in right of payment of principal, premium and interest to the Notes.

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Subsidiary means any subsidiary of the Company. A subsidiary of any Person means

(1) a corporation a majority of whose Voting Stock is at the time, directly or indirectly, owned by such Person, by one or more subsidiaries of such Person or by such Person and one or more subsidiaries of such Person,

(2) a partnership in which such Person or a subsidiary of such Person is, at the date of determination, a general or limited partner of such partnership, but only if such Person or its subsidiary is entitled to receive more than 50 percent of the assets of such partnership upon its dissolution, or

(3) any other Person (other than a corporation or partnership) in which such Person, directly or indirectly, at the date of determination thereof, has (x) at least a majority ownership interest or (y) the power to elect or direct the election of a majority of the directors or other governing body of such Person.

Subsidiary Guarantor means (a) each of the United States Subsidiaries on the Issue Date, other than Subsidiaries that are not guarantors of other Indebtedness of the Company in excess of a De Minimis Guaranteed Amount, (b) Chesapeake Eagle Canada Corp., a Canadian Subsidiary, and (c) each of the other Subsidiaries that becomes a guarantor of the Notes in compliance with the terms of the Indenture.

Volumetric Production Payments mean production payment obligations recorded as deferred revenue in accordance with GAAP, together with all undertakings and obligations in connection therewith.

Voting Stock means, with respect to any Person, securities of any class or classes of Capital Stock in such Person *entitling* the holders thereof (whether at all times or only so long as no senior class of stock has voting power by reason of contingency) to vote in the election of members of the Board of Directors or other governing body of such Person.

Events of Default

The following will be Events of Default with respect to the Notes:

(1) default by the Company or any Subsidiary Guarantor in the payment of principal of or premium, if any, on the Notes when due and payable at maturity, upon repurchase pursuant to the provisions described under Change of Control or pursuant to the covenant described under Limitation on Sale/Leaseback Transactions , upon acceleration or otherwise;

(2) default by the Company or any Subsidiary Guarantor for 30 days in payment of any interest on the Notes;

(3) default by the Company or any Subsidiary Guarantor in the deposit of any make-whole redemption payment;

(4) default on any other Indebtedness of the Company, any Subsidiary Guarantor or any other Subsidiary if either

(A) such default results in the acceleration of the maturity of any such Indebtedness having a principal amount of $50.0 million or more individually or, taken together with the principal amount of any other such Indebtedness the maturity of which has been so accelerated, in the aggregate, or

(B) such default results from the failure to pay when due principal of, premium, if any, or interest on, any such Indebtedness, after giving effect to any applicable grace period (a Payment Default), having a principal amount of $50.0 million or more individually or, taken together with the principal amount of any other Indebtedness under which there has been a Payment Default, in the aggregate;

provided that if any such default is cured or waived or any such acceleration is rescinded, or such Indebtedness is repaid, within a period of 30 days from the continuation of such default beyond any applicable grace period or the occurrence of such acceleration, as the case may be, such Event of Default and any consequent acceleration of the Notes shall be rescinded, so long as any such rescission does not conflict with any judgment or decree or applicable provision of law;

(5) default in the performance, or breach of, the covenant set forth in the covenant captioned Limitations on Mergers and Consolidations, or in the performance, or breach of, any other covenant or agreement of the Company or any Subsidiary Guarantor in the Indenture and failure to remedy such default within a period of 45 days after written notice thereof from the Trustee or Holders of 25% of the principal amount of the outstanding Notes;

(6) the entry by a court of one or more judgments or orders for the payment of money against the Company, any Subsidiary Guarantor or any other Subsidiary in an aggregate amount in excess of $50.0 million (net of applicable insurance coverage by a third party insurer which is acknowledged in writing by such insurer) that has not been vacated, discharged, satisfied or stayed pending appeal within 60 days from the entry thereof;

(7) the failure of a Guarantee by a Subsidiary Guarantor to be in full force and effect, or the denial or disaffirmance by such entity thereof; or

(8) certain events involving bankruptcy, insolvency or reorganization of the Company or any Subsidiary of the Company.

The Indenture provides that the Trustee may withhold notice to the Holders of the Notes of any default (except in payment of principal of, or premium, if any, or interest on the Notes) if the Trustee considers it in the interest of the Holders of the Notes to do so.

If an Event of Default occurs and is continuing, the Trustee or the Holders of not less than 25% in principal amount of the Notes outstanding may declare the principal of and premium, if any, and accrued but unpaid interest on all the Notes to be due and payable. Upon such a declaration, such principal, premium, if any, and interest will be due and payable immediately. If an Event of Default relating to certain events of bankruptcy, insolvency or reorganization of the Company or any Subsidiary of the Company occurs and is continuing, the principal of, and premium, if any, and interest on all the Notes will become and be immediately due and payable without any declaration or other act on the part of the Trustee or any Holders of the Notes. The amount due and payable on the acceleration of any Note will be equal to 100% of the principal amount of the Note, plus accrued and unpaid interest to the date of payment. Under certain circumstances, the Holders of a majority in principal amount of the outstanding Notes may rescind any such acceleration with respect to the Notes and its consequences.

No Holder of a Note may pursue any remedy under the Indenture unless

(1) the Trustee shall have received written notice of a continuing Event of Default,

(2) the Trustee shall have received a request from Holders of at least 25% in principal amount of the Notes to pursue such remedy,

(3) the Trustee shall have been offered indemnity reasonably satisfactory to it,

(4) the Trustee shall have failed to act for a period of 60 days after receipt of such notice, request and offer of indemnity and

(5) no direction inconsistent with such written request has been given to the Trustee during such 60-day period by the Holders of a majority in principal amount of the Notes;

provided, however, such provision does not affect the right of a Holder of any Note to sue for enforcement of any overdue payment thereon.

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The Holders of a majority in principal amount of the Notes then outstanding will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the Trustee, subject to certain limitations specified in the Indenture. The Indenture requires the annual filing by the Company with the Trustee of a written statement as to compliance with the covenants contained in the Indenture.

Modification and Waiver

Supplements and amendments to the Indenture or the Notes may be made by the Company, the Subsidiary Guarantors and the Trustee with the consent of the Holders of a majority in principal amount of the Notes then outstanding; *provided* that no such modification or amendment may, without the consent of the Holder of each Note then outstanding affected thereby,

(1) reduce the percentage of principal amount of Notes whose Holders must consent to an amendment or supplement;

(2) reduce the rate or change the time for payment of interest, including default interest, on any Note;

(3) reduce the principal amount of any Note or change the Maturity Date;

(4) reduce the redemption price, including premium, if any, payable upon redemption of any Note or change the time at which any Note may or shall be redeemed;

(5) reduce the purchase price payable upon the repurchase of any Note in connection with a Change of Control Offer or a Net Proceeds Offer, or change the time at which any Note may or shall be repurchased thereunder;

(6) make any Note payable in money other than that stated in such Note;

(7) impair the right to institute suit for the enforcement of any payment of principal of, or premium, if any, or interest on, any Note;

(8) make any change in the percentage of principal amount of Notes necessary to waive compliance with certain provisions of the Indenture; or

(9) waive a continuing Default or Event of Default in the payment of principal of, premium, if any, or interest on the Notes.

Supplements and amendments of the Indenture may be made by the Company, the Subsidiary Guarantors and the Trustee without the consent of any Holders of the Notes in certain limited circumstances, including

(1) to cure any ambiguity, omission, defect or inconsistency,

(2)

to provide for the assumption of the obligations of the Company or any Subsidiary Guarantor under the Indenture upon the merger, consolidation or sale or other disposition of all or substantially all of the assets of the Company or such Subsidiary Guarantor,

(3) to reflect the release of any Subsidiary Guarantor from its Guarantee of the Notes, or the addition of any Subsidiary of the Company as a Subsidiary Guarantor, in the manner provided in the Indenture,

(4) to comply with any requirement of the SEC in order to effect or maintain the qualification of the Indenture under the Trust Indenture Act or

(5) to make any change that would provide any additional benefit to the Holders or that does not adversely affect the rights of any Holder of the Notes in any material respect.

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The Holders of a majority in aggregate principal amount of the Notes then outstanding may waive any past default under the Indenture, except a default in the payment of principal, premium, if any, or interest.

Legal Defeasance and Covenant Defeasance

The Company may, at its option and at any time, elect to have its obligations discharged with respect to the outstanding Notes (Legal Defeasance). Such Legal Defeasance means that the Company will be deemed to have paid and discharged the entire Indebtedness represented by such Notes, except for

(1) the rights of Holders of the Notes to receive payments solely from the trust fund described in the following paragraph in respect of the principal of, premium, if any, and interest on the Notes when such payments are due,

(2) the Company s obligations with respect to the Notes concerning the issuance of temporary Notes, transfers and exchanges of the Notes, replacement of mutilated, destroyed, lost or wrongfully taken Notes, the maintenance of an office or agency where the Notes may be surrendered for transfer or exchange or presented for payment, and duties of paying agents,

(3) the rights, powers, trusts, duties and immunities of the Trustee, and the Company s obligations in connection therewith and

(4) the Legal Defeasance provisions of the Indenture.

In addition, the Company may, at its option and at any time, elect to have the obligations of the Company released with respect to certain covenants described under Certain Covenants (Covenant Defeasance), and thereafter any omission to comply with such obligations shall not constitute a Default or Event of Default. In the event Covenant Defeasance occurs, certain events (not including non-payment) described under Events of Default will no longer constitute an Event of Default. If we exercise our Legal Defeasance or Covenant Defeasance option, each Subsidiary Guarantor will be released from all its obligations under the Indenture and its Guarantee.

In order to exercise either Legal Defeasance or Covenant Defeasance under the Indenture,

(1) the Company must irrevocably deposit with the Trustee, in trust, for the benefit of the Holders of the Notes, cash in euro, European Government Obligations, or a combination thereof, in such amounts as will be sufficient, in the opinion of a nationally recognized firm of independent public accountants, to pay the principal of, premium, if any, and interest on the outstanding amount of the Notes on the Maturity Date or on the applicable redemption date, as the case may be, of such principal or installment of principal, premium, if any, or interest;

(2) in the case of Legal Defeasance, the Company must deliver to the Trustee an opinion of counsel confirming that

(a) the Company has received from or there has been published by, the Internal Revenue Service a ruling or

(b) since the date of the Indenture, there has been a change in the applicable U.S. Federal income tax law, in either case to the effect that, and based thereon such opinion of counsel shall confirm that, the Holders of the Notes will not recognize income, gain or loss for U.S. Federal income tax purposes as a result of such Legal Defeasance and will be subject to U.S. Federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

(3) in the case of Covenant Defeasance, the Company shall have delivered to the Trustee an opinion of counsel to the effect that the Holders of the Notes will not recognize income, gain or loss for U.S.

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Federal income tax purposes as a result of such Covenant Defeasance and will be subject to U.S. Federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;

(4) no Default or Event of Default shall have occurred and be continuing on the date of such deposit or insofar as Events of Default from bankruptcy or insolvency events are concerned, at any time in the period ending on the 91st day after the date of deposit;

(5) such Legal Defeasance or Covenant Defeasance shall not result in a breach or violation of, or constitute a default under the Indenture or any other material agreement or instrument to which the Company is a party or by which the Company is bound;

(6) the Company shall have delivered to the Trustee an officers certificate stating that the deposit was not made by the Company with the intent of preferring the Holders of the Notes over other creditors of the Company or with the intent of defeating, hindering, delaying or defrauding creditors of the Company or others; and

(7) the Company shall have delivered to the Trustee an officers certificate and an opinion of counsel each stating that the Company has complied with all conditions precedent provided for relating to the Legal Defeasance or the Covenant Defeasance.

Governing Law

The Indenture provides that it and the Notes will be governed by, and construed in accordance with, the laws of the State of New York.

The Trustee

The Bank of New York Trust Company, N.A. is the Trustee under the Indenture. The Bank of New York Trust Company, N.A. also serves as trustee for our 7.5% Senior Notes due 2013, our 7.625% Senior Notes due 2013, our 7% Senior Notes due 2014, our 7.5% Senior Notes due 2014, our 7.75% Senior Notes due 2015, our 6.375% Senior Notes due 2015, our 6.875% Senior Notes due 2016, our 6.625% Senior Notes due 2016, our 6.5% Senior Notes due 2017, our 6.25% Senior Notes due 2018, our 6.875% Senior Notes due 2020 and our 2.75% Contingent Convertible Senior Notes due 2035. We may also maintain banking and other commercial relationships with the Trustee and its affiliates in the ordinary course of business, and the Trustee may own our debt securities. The Trustee s address is 2 North LaSalle Street, Suite 1020, Chicago, Illinois 60602. The Company has also appointed the Trustee as the initial registrar and paying agent in the U.S. under the Indenture.

The Trustee is permitted to become an owner or pledgee of the Notes and may otherwise deal with the Company or its Subsidiaries or Affiliates with the same rights it would have if it were not Trustee. If, however, the Trustee acquires any conflicting interest (as defined in the Trust Indenture Act) after an Event of Default has occurred and is continuing, it must eliminate such conflict or resign.

In case an Event of Default shall occur (and be continuing), the Trustee will be required to use the degree of care and skill of a prudent person in the conduct of such person s own affairs. The Trustee will be under no obligation to exercise any of its powers under the Indenture at the request of any of the Holders of the Notes, unless such Holders have offered the Trustee indemnity reasonably satisfactory to it.

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Book-Entry, Delivery and Form

General

Notes sold will be represented by one or more global notes in registered form without interest coupons attached (collectively, the Global Notes). The Notes will be issued in denominations of 50,000 and in any integral multiple of 1,000 in excess thereof. The Global Notes will be deposited with, or on behalf of, a common depositary for the accounts of Euroclear and Clearstream and registered in the name of the nominee of the common depositary.

Ownership of interests in the Global Notes (the Book-Entry Interests) will be limited to persons that have accounts with Euroclear and/or Clearstream, or persons that hold interests through such participants or otherwise in accordance with applicable transfer restrictions set out in the indenture governing the Notes and any applicable securities laws of any state of the United States or any other jurisdiction. Euroclear and Clearstream will hold interests in the Global Notes on behalf of their participants through customers securities accounts in their respective names on the books of their respective depositaries. Except under the limited circumstances described below, owners of beneficial interests in the Global Notes will not be entitled to receive physical delivery of certificated Notes.

Book-Entry Interests will be shown on, and transfers thereof will be done only through, records maintained in book-entry form by Euroclear and Clearstream and their respective participants. The laws of some jurisdictions, including certain states of the United States, may require that certain purchasers of securities take physical delivery of such securities in definitive form. The foregoing limitations may impair your ability to own, transfer or pledge Book-Entry Interests. In addition, while the Notes are in global form, holders of Book-Entry Interests will not be considered the owners or Holders of Notes for any purpose.

So long as the Notes are held in global form, Euroclear and/or Clearstream (or their respective nominees), as applicable, will be considered the sole Holders of Global Notes for all purposes under the indenture. In addition, participants in Euroclear and/or Clearstream must rely on the procedures of Euroclear and/or Clearstream, as the case may be, and indirect participants must rely on the procedures of Euroclear, Clearstream and the participants through which they own Book-Entry Interests, to transfer their interests or to exercise any rights of Holders under the Indenture.

Neither we nor the Trustee under the Indenture and neither the registrar nor the transfer agent will have any responsibility or be liable for any aspect of the records relating to the Book-Entry Interests.

Redemption of the Global Notes

In the event any Global Note (or any portion thereof) is redeemed, Euroclear and/or Clearstream (or their respective nominees), as applicable, will redeem an equal amount of the Book-Entry Interests in such Global Note from the amount received by it in respect of the redemption of such Global Note. The redemption price payable in connection with the redemption of such Book-Entry Interests will be equal to the amount received by Euroclear and Clearstream, as applicable, in connection with the redemption of such Global Note (or any portion thereof). We understand that, under existing practices of Euroclear and Clearstream, if fewer than all of the Notes are to be redeemed at any time, Euroclear and Clearstream will credit their respective participants accounts on a proportionate basis (with adjustments to prevent fractions) or by lot or on such other basis as they deem fair and appropriate; provided, however, that no book-entry interest of 50,000 principal amount or less may be redeemed in part.

Payments on Global Notes

We will make payments of any amounts owing in respect of the Global Notes (including principal, premium and interest, if any) to the common depositary or its nominee, which will distribute such

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payments to participants in accordance with their procedures. We expect that standing customer instructions and customary practices will govern payments by participants to owners of Book-Entry Interests held through such participants.

Under the terms of the Indenture, we and the Trustee will treat the registered Holders of the Global Notes (e.g., Euroclear or Clearstream (or their respective nominees)) as the owners thereof for the purpose of receiving payments and for all other purposes. Consequently, neither we nor the Trustee nor any of our or its respective agents has or will have any responsibility or liability for:

- any aspect of the records of Euroclear, Clearstream or any participant or indirect participant relating to payments made on account of a Book-Entry Interest or for maintaining, supervising or reviewing the records of Euroclear, Clearstream or any participant or indirect participant relating to or payments made on account of a Book-Entry Interest; or
- Euroclear, Clearstream or any participant or indirect participant.

Payments by participants to owners of Book-Entry Interests held through participants are the responsibility of such participants.

Currency of Payment for the Global Notes

Except as may otherwise be agreed between Euroclear and/or Clearstream and any Holder, the principal of, premium, if any, and interest on, and all other amounts payable in respect of, the Global Notes will be paid to owners of Book-Entry Interests in such Notes (the Euroclear/Clearstream Holders) through Euroclear and/or Clearstream in euro.

Payments will be subject in all cases to any fiscal or other laws and regulations (including any regulations of the applicable clearing system) applicable thereto. Neither we nor the Trustee nor the underwriters nor any of our or their respective agents will be liable to any Holder of a Global Note or any other person for any commissions, costs, losses or expenses in relation to or resulting from any currency conversion or rounding effected in connection with any such payment.

Action by Owners of Book-Entry Interests

Euroclear and Clearstream have advised us that they will take any action permitted to be taken by a Holder of Notes (including the presentation of Notes for exchange as described below) only at the direction of one or more participants to whose account the Book-Entry Interests in the Global Notes are credited and only in respect of such portion of the aggregate principal amount of Notes as to which such participant or participants has or have given such direction. Euroclear and Clearstream will not exercise any discretion in the granting of consents, waivers or the taking of any other action in respect of the Global Notes. However, if there is an Event of Default, each of Euroclear and Clearstream reserves the right to exchange the relevant Global Notes for definitive registered Notes in certificated form (the Definitive Registered Notes), and to distribute Definitive Registered Notes to its participants.

Transfers

Transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of Euroclear and Clearstream and their respective direct or indirect participants, which rules and procedures may change from time to time.

Any Book-Entry Interest in one of the Global Notes that is transferred to a person who takes delivery in the form of a Book-Entry Interest in any other Global Note will, upon transfer, cease to be a Book-Entry Interest in the first-mentioned Global Note and become a Book-Entry Interest in such other Global Note, and accordingly will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to Book-Entry Interests in such other Global Note for as long as it remains such a Book-Entry Interest.

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Definitive Registered Notes

Under the terms of the Indenture, owners of the Book-Entry Interests will receive Definitive Registered Notes:

- if Euroclear or Clearstream notifies us that it is unwilling or unable to continue as depositary for the Global Note, and we fail to appoint a successor;
- if Euroclear or Clearstream so requests following an event of default under the Indenture; or
- if the owner of a Book-Entry Interest requests such exchange in writing delivered through either Euroclear or Clearstream, as applicable, following an event of default under the Indenture.

Euroclear has advised the issuer that upon request by an owner of a Book-Entry Interest, its current procedure is to request that the issuer issue or cause to be issued Definitive Registered Notes to all owners of Book-Entry Interests.

In such an event, the registrar will issue Definitive Registered Notes, registered in the name or names and issued in any approved denominations, requested by or on behalf of Euroclear and/or Clearstream, as applicable (in accordance with their respectively customary procedures and based upon directions received from participants reflecting the beneficial ownership of Book-Entry Interests).

In the case of the issuance of Definitive Registered Notes, the Holder of a Definitive Registered Note may transfer such Note by surrendering it to the transfer agent. In the event of a partial transfer or a partial redemption of a holding of Definitive Registered Notes represented by one Definitive Registered Note, a Definitive Registered Note will be issued to the transferee in respect of the part transferred, and a new Definitive Registered Note in respect of the balance of the holding not transferred or redeemed will be issued to the transferor or the Holder, as applicable; provided that Definitive Registered Notes will be issued in denominations of 50,000 and in any integral multiple of 1,000 in excess thereof. We will bear the cost of preparing, printing, packaging and delivering the Definitive Registered Notes. Holders of the Book-Entry Interests may incur fees normally payable in respect of the maintenance and operation of accounts in Euroclear and/or Clearstream.

If Definitive Registered Notes are issued and a Holder thereof claims that such Definitive Registered Notes have been lost, destroyed or wrongfully taken or if such Definitive Registered Notes are mutilated and are surrendered to the registrar or at the office of a transfer agent, we will issue and the Trustee will authenticate a replacement Definitive Registered Note if the Trustee s requirements are met. We or the Trustee may require a Holder requesting replacement of a Definitive Registered Note to furnish an indemnity bond sufficient in the judgment of both the Trustee and us to protect us, the Trustee, any transfer agent or any paying agent appointed pursuant to the indenture from any loss which any of them may suffer if a Definitive Registered Note is replaced. We may charge for its expenses in replacing a Definitive Registered Note.

In case any such mutilated, destroyed, lost or wrongfully taken Definitive Registered Note has become or is about to become due and payable, or is about to be redeemed or purchased by us pursuant to the provisions of the Indenture, we in our discretion may, instead of issuing a new Definitive Registered Note, pay, redeem or purchase such Definitive Registered Note, as the case may be.

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Definitive Registered Notes may be transferred and exchanged for Book-Entry Interests in a Global Note only in accordance with the Indenture.

Global Clearance and Settlement Under the Book-Entry System

Initial Settlement

Initial settlement for the Notes will be made in euro. Book-Entry Interests owned through depositary accounts will follow the settlement procedures applicable to conventional eurobonds in registered form. Book-Entry Interests held through Euroclear and Clearstream will be credited to the securities custody account of Euroclear and Clearstream Holders on the business day following the settlement date against payment for value on the settlement date.

Secondary Market Trading

The Book-Entry Interests will trade through participants of the relevant depositary, and will settle in same day funds. Since the purchase determines the place of delivery, it is important to establish at the time of trading any Book-Entry Interests where both the purchaser s and seller s accounts are located to ensure that settlement can be made on the desired value date.

Special Timing Considerations

You should be aware that investors will only be able to make and receive deliveries, payments and other communications involving Notes through Euroclear or Clearstream on days when those systems are open for business.

In addition, because of time-zone differences, there may be complications with completing transactions involving Clearstream and/or Euroclear on the same business day as in the United States. U.S. investors who wish to transfer their interests in the Notes, or to receive or make a payment or delivery of Notes, on a particular day, may find that the transactions will not be performed until the next business day in Luxembourg if Clearstream is used, or Brussels if Euroclear is used.

Clearing Information

We expect that the Notes will be accepted for clearance through the facilities of Euroclear and Clearstream. The international securities identification numbers and common codes for the Notes are set out under Listing and General Information Clearing Information.

Information Concerning Euroclear and Clearstream

The preceding description of the operations and procedures of Euroclear and Clearstream is provided solely as a matter of convenience. These operations and procedures are solely within the control of the relevant settlement systems and are subject to changes by them. We take no responsibility for these operations and procedures and urge investors to contact the systems or their participants directly to discuss these matters.

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We understand as follows with respect to Euroclear and Clearstream:

Euroclear and Clearstream hold securities for participating organizations. They also facilitate the clearance and settlement of securities transactions between their respective participants through electronic book-entry changes in the accounts of such participants. Euroclear and Clearstream provide various services to their participants, including the safekeeping, administration, clearance, settlement, lending and borrowing of internationally traded securities. Euroclear and Clearstream interface with domestic securities markets. Euroclear and Clearstream participants are financial institutions such as underwriters, securities brokers and dealers, banks, trust companies and certain other organizations. Indirect access to Euroclear or Clearstream is also available to others such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Euroclear or Clearstream participant, either directly or indirectly.

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DESCRIPTION OF CERTAIN OTHER INDEBTEDNESS

The following is a summary of certain of our indebtedness that will be outstanding following the consummation of this offering. To the extent this summary contains descriptions of our revolving bank credit facility, our 7.5% Senior Notes due 2013, our 7.625% Senior Notes due 2013, our 7% Senior Notes due 2014, our 7.5% Senior Notes due 2014, our 7.75% Senior Notes due 2015, our 6.375% Senior Notes due 2015, our 6.875% Senior Notes due 2016, our 6.625% Senior Notes due 2016, our 6.5% Senior Notes due 2017, our 6.25% Senior Notes due 2018, our 6.875% Senior Notes due 2020 and our 2.75% Contingent Convertible Senior Notes due 2035, and the indentures governing them, the descriptions do not purport to be complete and are qualified in their entirety by reference to those and related documents, copies of which we will provide you upon request.

Our Revolving Bank Credit Facility

Our revolving bank credit facility limits our borrowings to the lesser of the borrowing base and the total commitments (currently both are $2.5 billion) and matures in February 2011. As of November 30, 2006, we had outstanding borrowings of $1.952 billion under this facility and had $6.165 million of the facility securing various letters of credit. Borrowings under the facility are collateralized by some of our producing oil and gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California N.A. or the U.S. federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies based on our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies according to our senior unsecured long-term debt ratings. As of September 30, 2006, the annual commitment fee rate was 0.25%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. The credit agreement contains various covenants and restrictive provisions, including those restricting our ability to incur additional indebtedness, make investments or loans and create liens. The credit agreement requires us to maintain an indebtedness to EBITDA ratio (as defined in the credit agreement) not to exceed 3.5 to 1 and an indebtedness to total capitalization ratio (as defined in the credit agreement) not to exceed 0.65 to 1.

Our Senior Notes

At September 30, 2006, we had outstanding senior notes in an aggregate principal amount of $5.8 billion, which, together with our $690 million aggregate principal amount of 2.75% Contingent Convertible Senior Notes due 2035, represented the remainder of our long-term debt. At the date of this prospectus, we have issued and outstanding $363.8 million in principal amount of 7.5% Senior Notes due 2013, $500 million in principal amount of 7.625% Senior Notes due 2013, $300.0 million in principal amount of 7% Senior Notes due 2014, $300.0 million in principal amount of 7.5% Senior Notes due 2014, $300.4 million in principal amount of 7.75% Senior Notes due 2015, $600.0 million in principal amount of 6.375% Senior Notes due 2015, $670.4 million in principal amount of 6.875% Senior Notes due 2016, $600.0 million principal amount of 6.625% Senior Notes due 2016, $1.1 billion principal amount of 6.5% Senior Notes due 2017, $600.0 million principal amount of 6.25% Senior Notes due 2018 and $500.0 million principal amount of 6.875% Senior Notes due 2020. There are no scheduled principal payments required on any of these senior notes until their final maturities.

Our outstanding senior notes are senior, unsecured obligations that rank pari passu in right of payment with all of our existing and future senior indebtedness, including the notes offered hereby, and rank senior in right of payment to all of our future subordinated indebtedness. Our outstanding senior notes are fully and unconditionally guaranteed, jointly and severally, by certain of our United States subsidiaries and one of our non-United States subsidiaries.

Our existing senior note indentures (other than the indentures governing the 7.625% Senior Notes due 2013, the 6.50% Senior Notes due 2017 and the 6.875% Senior Notes due 2020) restrict our and our

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restricted subsidiaries ability to incur additional indebtedness. Please read Risk Factors Risks Relating to Our Business Lower oil and natural gas prices could negatively impact our ability to borrow. As of September 30, 2006, we estimate that secured bank indebtedness of $5.4 billion could have been incurred within those restrictions. These restrictions under such indentures will not apply to any future unrestricted subsidiaries. There are no unrestricted subsidiaries under our indentures as of the date of this prospectus.

Our existing senior note indentures (other than the indentures governing the 7.625% Senior Notes due 2013, the 6.50% Senior Notes due 2017 and the 6.875% Senior Notes due 2020) also limit our ability to make restricted payments, including the payment of cash dividends, unless certain tests are met.

We also have issued and outstanding $690 million aggregate principal amount of 2.75% Contingent Convertible Senior Notes due 2035 (the Convertible Senior Notes). The Convertible Senior Notes are senior unsecured obligations and rank pari passu in right of payment to all of our existing and future senior indebtedness, including the notes offered hereby, and rank senior in right of payment to all of our future subordinated indebtedness. The Convertible Senior Notes are guaranteed by certain of our existing United States subsidiaries and one of our non-United States subsidiaries and by certain of our future United States subsidiaries on a senior unsecured basis. The indenture governing the Convertible Senior Notes does not have any financial or restricted payment covenants.

The Convertible Senior Notes will be convertible, at the holder s option, prior to the maturity date under certain circumstances, using a net share settlement process, into cash and, in some circumstances, our common stock. In general, upon conversion of a Convertible Senior Note, the holder of such note 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 during any six-month interest period, beginning with the six-month period ending May 14, 2016, under certain conditions.

The Convertible Senior Notes mature on November 15, 2035. We may redeem the Convertible Senior Notes, in whole at any time, or in part from time to time, on or after November 15, 2015 at a redemption price, payable in cash, of 100% of the principal amount of such notes, plus accrued and unpaid interest.

Holders of the Convertible Senior Notes may require us to repurchase all or a portion of their notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes, plus accrued and unpaid interest, payable in cash. Upon a fundamental change, as defined in the indenture governing the Convertible Senior Notes, holders may require us to repurchase all or a portion of their notes, payable in cash equal to 100% of the principal amount of the notes plus accrued and unpaid interest.

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MATERIAL UNITED STATES FEDERAL TAX CONSIDERATIONS

General

The following discussion summarizes the material U.S. Federal income and certain estate tax consequences of the purchase, ownership and disposition of the notes by an initial holder of the notes who purchases the notes for cash at the original offering price, who holds the notes as capital assets (generally property held for investment) and who does not have a special tax status. This discussion is based upon the Internal Revenue Code of 1986, as amended (the Code), Treasury Regulations, and judicial decisions and administrative interpretations thereunder, as of the date hereof, all of which are subject to change, possibly with retroactive effect, or are subject to different interpretations. We cannot assure you that the Internal Revenue Service (the IRS) will not challenge one or more of the tax consequences described herein, and we have not obtained, nor do we intend to obtain, a ruling from the IRS or an opinion of counsel with respect to the U.S. Federal tax consequences of purchasing, owning or disposing of the notes.

In this discussion, we do not purport to address all tax considerations that may be important to a particular holder in light of the holder s circumstances, or to certain categories of investors (such as financial institutions, insurance companies, tax-exempt organizations, dealers or traders in securities or currencies, persons who hold the notes through partnerships or other pass-through entities, regulated investment companies, real estate investment trusts, U.S. persons whose functional currency is not the U.S. dollar, persons liable for alternative minimum tax, U.S. expatriates or persons who hold the notes as part of a hedge, conversion transaction, straddle or other risk reduction transaction) that may be subject to special rules. This discussion also does not address the tax considerations arising under the laws of any foreign, state or local jurisdiction.

If a partnership (including an entity treated as a partnership for U.S. Federal income tax purposes) holds notes, the tax treatment of a partner generally will depend upon the status of the partner and upon the activities of the partnership. If you are a partner of a partnership holding notes, we suggest that you consult your tax advisor.

YOU SHOULD CONSULT YOUR OWN TAX ADVISORS AS TO THE PARTICULAR TAX CONSEQUENCES TO YOU OF THE ACQUISITION, OWNERSHIP AND DISPOSITION OF THE NOTES, INCLUDING THE EFFECT AND APPLICABILITY OF STATE, LOCAL OR FOREIGN TAX LAWS.

Consequences to U.S. Holders

You are a U.S. holder for purposes of this discussion if you are a beneficial owner of notes and you are:

- an individual U.S. citizen or resident alien;

- a corporation, or other entity taxable as a corporation for U.S. Federal income tax purposes, that was created or organized in or under the laws of the United States, any state thereof or the District of Columbia;

an estate whose world-wide income is subject to U.S. Federal income taxation; or

a trust that either is subject to the supervision of a court within the United States and which has one or more United States persons with authority to control all substantial decisions or has a valid election in effect under applicable U.S. Treasury Regulations to be treated as a United States person.

Because the notes provide for the payment of additional amounts under certain circumstances (see Description of Notes Make-Whole Redemption), the notes may be subject to U.S. Treasury Regulations applicable to debt instruments that provide for one or more contingent payments. Under such Treasury Regulations, if the payment of additional amounts on the notes is, as of the issue date, neither a remote contingency nor an incidental contingency, the U.S. federal income tax consequences to a

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U.S. holder would be different from those discussed below. We intend to take the position that the payment of additional amounts is a remote or incidental contingency. Our determination that such payments are a remote or incidental contingency for these purposes is binding on a U.S. holder unless such U.S. holder discloses to the IRS that it is taking a contrary position. It is possible, however, that the IRS may take a contrary position from that described above, in which case the tax consequences to a holder could differ materially and adversely from those described below. The remainder of this discussion assumes that the notes are not contingent payment debt instruments under the U.S. Treasury Regulations. Prospective investors should consult with their own tax advisors as to the tax consequences that relate to the possibility of additional payments.

Purchase of Notes

The conversion of U.S. dollars into euro and the immediate use of that currency to purchase notes generally will not result in taxable gain or loss. However, if you use previously acquired euro to purchase notes, you will generally recognize ordinary currency exchange gain or loss at the time of purchase. Such currency exchange gain or loss will generally be the difference between the U.S. dollar value of those euro based on the spot rate on the date the notes are purchased and your tax basis in those euro, which will generally be the U.S. dollar value of the euro based on the spot exchange rate on the date the euro were acquired by you. For purposes of this discussion, spot rate generally means a currency exchange rate that reflects a market exchange rate available to the public for cash.

Interest

Interest payable on the notes will generally be included in the gross income of a U.S. holder as ordinary interest income at the time it is accrued or received, in accordance with such U.S. holder s method of accounting for U.S. federal income tax purposes.

If you are a cash method taxpayer (including most individual holders), you will be taxed on the U.S. dollar value of the euro you receive as interest when you receive them. The U.S. dollar value of the euro will be determined using the spot rate in effect at such time.

If you are an accrual method taxpayer, you will be taxed on the U.S. dollar value of the euro as the interest accrues on the notes. In determining the U.S. dollar value of the euro for this purpose, you may use the average euro exchange rate during the relevant interest accrual period (or, if that period spans two taxable years, during the portion of the interest accrual period in the relevant taxable year). The average rate for an accrual period (or partial period) is the simple average of the spot rates for each business day of such period, or other average exchange rate for the period reasonably derived and consistently applied by you. When interest is actually paid, you will generally also recognize currency exchange gain or loss, taxable as ordinary income or loss from sources within the United States, equal to the difference between (a) the value of the euro received as interest, as translated into U.S. dollars using the spot rate on the date of receipt, and (b) the U.S. dollar amount previously included in income with respect to such payment. If you do not wish to accrue interest income using the average exchange rate, certain alternative elections may be available.

Your tax basis in the euro you receive as interest will be the aggregate amount reported by you as income with respect to the receipt of the euro. If you subsequently sell those euro, additional tax consequences will apply as described in Sale of euro.

Disposition of the Notes

On the sale, exchange, redemption, retirement, or other taxable disposition of your notes:

- If you receive proceeds on the disposition of your notes in the form of U.S. dollars, you will be considered to have received the principal in the form of euro and to have sold those euro for U.S. dollars.

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You will have taxable gain or loss equal to the difference between the amount realized by you (less any amount attributable to accrued but unpaid interest to the extent not previously included in income) and your tax basis in the notes. The amount realized on the disposition of your notes will generally be the U.S. dollar value of the euro you receive (or are considered to receive) based on the spot exchange rate on the date of disposition. Your tax basis in the notes is the U.S. dollar value of the amount in euro paid for the notes, determined on the date of purchase.

Any such gain or loss (except to the extent attributable to foreign currency gain or loss) will be capital gain or loss, and will be long term capital gain or loss if you held the notes for more than one year. Long term capital gain recognized by certain U.S. holders (including individuals) is currently subject to taxation at reduced rates. The deductibility of capital losses may be subject to limitations.

You will realize foreign currency gain or loss to the extent the U.S. dollar value of the euro that you paid for the notes, based on the spot rate at the time you dispose of the notes, is greater or less than the U.S. dollar value of the euro that you paid for the notes, based on the spot rate at the time you acquired the notes. Any resulting foreign currency gain or loss will be U.S.-source ordinary income or loss. You will only recognize such foreign currency gain or loss to the extent you have gain or loss, respectively, on the overall sale, retirement, or other disposition of the notes.

If you sell notes between interest payment dates, a portion of the amount you receive reflects interest that has accrued on the notes but has not yet been paid by the sale date. That amount is treated as ordinary interest income and not as sale proceeds.

Your tax basis in the euro you receive on sale or retirement of the notes will be the value of euro reported by you as received on the sale or retirement of the notes. If you receive euro on retirement of the notes and subsequently sell those euro, or if you are considered to receive euro on retirement of the notes and those euro are considered to be sold for U.S. dollars on your behalf, or if you sell the notes for euro and subsequently sell those euro, additional tax consequences will apply as described in Sale of euro.

Sale of euro

If you receive euro from the sale, exchange, redemption, retirement, or other taxable disposition of a note, and you later sell those euro (or euro you received as interest on the notes) for U.S. dollars, you will have taxable gain or loss equal to the difference between the amount of U.S. dollars received and your tax basis in the euro. Any such gain or loss is foreign currency gain or loss taxable as ordinary income or loss.

Consequences to Non-U.S. Holders

You are a non-U.S. holder for purposes of this discussion if you are a beneficial owner of notes (other than an entity treated as a partnership for U.S. Federal income tax purposes) and you are not a U.S. holder.

U.S. Federal Withholding Tax

The 30% U.S. Federal withholding tax generally will not apply to any payment of principal or interest on the notes under the portfolio interest exemption provided that interest on the notes is not effectively connected with your conduct of a trade or business in the United States, you provide the appropriate certification, as described below, and:

- you do not actually or constructively own 10% or more of the total combined voting power of all classes of our voting stock within the meaning of the Code and applicable Treasury Regulations;

- you are not a controlled non-U.S. corporation that is related to us (directly or indirectly) through stock ownership; and

- you are not a bank whose receipt of interest on the notes is pursuant to a loan agreement entered into in the ordinary course of business.

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The exemption from withholding tax will not apply unless (a) you provide your name and address on an IRS Form W-8BEN (or successor form), and certify under penalties of perjury, that you are not a United States person, (b) a financial institution holding the notes on your behalf certifies, under penalties of perjury, that it has received an IRS Form W-8BEN (or successor form) from you and must provide us with a copy, or (c) you hold your notes directly through a qualified intermediary, and the qualified intermediary has sufficient information in its files indicating that you are not a U.S. holder. A qualified intermediary is a bank, broker or other intermediary that is acting out of a non-U.S. branch or office and has signed an agreement with the IRS providing that it will administer all or part of the U.S. Federal tax withholding rules under specified procedures.

If you cannot satisfy the requirements described above, payments of principal and interest made to you will be subject to the 30% U.S. Federal withholding tax, unless you provide us with a properly executed (1) IRS Form W-8BEN or successor form claiming an exemption from or a reduction of withholding under the benefit of a tax treaty or (2) IRS Form W-8ECI (or successor form) stating that interest paid on the notes is not subject to withholding tax because it is effectively connected with your conduct of a trade or business in the United States.

U.S. Federal Income Tax

Interest. If you are engaged in a trade or business in the United States and interest on the notes is effectively connected with the conduct of that trade or business (and, in the case of an applicable tax treaty, is attributable to a U.S. permanent establishment maintained by you), you will be subject to U.S. Federal income tax on the interest on a net income basis (although exempt from the 30% withholding tax) in the same manner as if you were a United States person as defined under the Code. In addition, if you are a non-U.S. corporation, you may be subject to a branch profits tax equal to 30% (or lower applicable treaty rate) of your earnings and profits for the taxable year, including earnings and profits from an investment in the notes, that are effectively connected with the conduct by you of a trade or business in the United States.

Sale, Exchange, Redemption or Other Disposition of the Notes. Any gain or income realized on the sale, exchange, redemption or other disposition of the notes generally will not be subject to U.S. Federal income tax unless:

- that gain or income is effectively connected with the conduct of a trade or business in the United States by you (and, in the case of an applicable tax treaty, is attributable to a U.S. permanent establishment maintained by you),

- you are an individual who is present in the United States for 183 days or more in the taxable year of that disposition, and certain other conditions are present, or

- the gain represents accrued interest, in which case the rules for taxation of interest would apply.

If you are a holder subject to U.S. Federal income tax under the first bullet point, you will be taxed on a net income basis in the same manner as if you were a United States person as defined under the Code. In addition, if you are a non-U.S. corporation, you may be subject to a branch profits tax as explained above. Holders subject to U.S. Federal income tax under the second bullet point will be taxed on the net gain at a 30% rate.

U.S. Federal Estate Tax

Your estate will not be subject to U.S. Federal estate tax on notes beneficially owned by you at the time of your death, provided that interest on the notes is exempt from U.S. Federal withholding tax under the portfolio interest exemption (without regard to the certification requirement) described in the first paragraph of Consequences to Non-U.S. Holders U.S. Federal Withholding Tax above.

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Backup Withholding and Information Reporting

U.S. Holders

Information reporting will apply to payments of principal and interest made by us on, or the proceeds of the sale or other disposition of, the notes with respect to certain noncorporate U.S. holders, and backup withholding, currently at a rate of 28%, may apply unless the recipient of such payment provides the appropriate intermediary with a taxpayer identification number, certified under penalties of perjury, as well as certain other information or otherwise establishes an exemption from backup withholding. Any amount withheld under the backup withholding rules is allowable as a credit against the U.S. holder s U.S. Federal income tax liability, provided the required information is timely provided to the IRS.

Non-U.S. Holders

Payments to you of interest on a note and amounts withheld from such payments, if any, generally will be reported to the IRS and you. Backup withholding will not apply to payments of principal and interest on the notes if you certify as to your non-U.S. holder status on an IRS Form W-8BEN (or successor form) under penalties of perjury or you otherwise qualify for an exemption (provided that neither we nor our agent know or have reason to know that you are a United States person or that the conditions of any other exemptions are not in fact satisfied).

The payment of the proceeds of the disposition of notes to or through the U.S. office of a U.S. or non-U.S. broker will be subject to information reporting and backup withholding unless you provide the certification described above or you otherwise qualify for an exemption. The proceeds of a disposition effected outside the United States by a non-U.S. holder to or through a non-U.S. office of a broker generally will not be subject to backup withholding or information reporting. However, if such broker is a United States person, a controlled non-U.S. corporation, a non-U.S. person 50% or more of whose gross income from all sources for certain periods is effectively connected with a trade or business in the United States, or a non-U.S. partnership that is engaged in the conduct of a trade or business in the United States or that has one or more partners that are United States persons who in the aggregate hold more than 50% of the income or capital interests in the partnership, information reporting requirements will apply unless such broker has documentary evidence in its files of the holder s non-U.S. status and has no actual knowledge or reason to know to the contrary or unless the holder otherwise qualifies for an exemption. Any amount withheld under the backup withholding rules is allowable as a credit against your U.S. Federal income tax liability, if any, provided the required information or appropriate claim for refund is provided to the IRS.

EU DIRECTIVE ON THE TAXATION OF SAVINGS INCOME

On June 3, 2003, the Council of the EU adopted the Directive on the taxation of savings income pursuant to which a Member State is generally required to provide the tax authorities of another Member State with details on payments of interest or other similar income paid by a person within its jurisdiction to or for an individual resident in the other Member State. Exceptionally (and for a transitional period only, which will end after agreement on exchange of information has been reached between the EU and certain non-EU States), Belgium, Luxembourg and Austria will, instead, be required to withhold tax from such payments unless bondholders either authorize the person making the payment to report the payment as described above or present a certificate from the relevant tax authority establishing exemption therefrom. The Directive applies since July 1, 2005.

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UNDERWRITING

We, the subsidiary guarantors, and the underwriters for the offering named below have entered into an underwriting agreement with respect to the notes. Subject to certain conditions, each underwriter has severally agreed to purchase the principal amount of notes indicated in the following table.

Underwriters	Principal Amount of Notes
Barclays Bank PLC	150,000,000
Credit Suisse Securities (Europe) Limited	60,000,000
Deutsche Bank Securities Inc.	60,000,000
Goldman Sachs International	60,000,000
ABN AMRO Incorporated	30,000,000
Banc of America Securities Limited	30,000,000
BNP Paribas Securities Corp.	30,000,000
Fortis Securities LLC	30,000,000
Lehman Brothers International (Europe)	30,000,000
The Royal Bank of Scotland plc	30,000,000
UBS Limited	30,000,000
Bayerische Hypo- und Vereinsbank AG	9,500,000
BMO Capital Markets Corp.	9,500,000
Calyon Securities (USA) Inc.	9,500,000
DZ Financial Markets LLC	3,000,000
Natexis Bleichroeder Inc.	9,500,000
Royal Bank of Canada Europe Limited	9,500,000
The Toronto-Dominion Bank	9,500,000
Total	600,000,000

The underwriters are committed to take and pay for all of the notes being offered, if any are taken.

Notes sold by the underwriters to the public will initially be offered at the initial public offering price set forth on the cover of this prospectus.

The notes are a new issue of securities with no established trading market. We have been advised by the underwriters that the underwriters intend to make a market in the notes but are not obligated to do so and may discontinue market making at any time without notice. No assurance can be given as to the liquidity of the trading market for the notes.

In connection with the offering, the underwriters may purchase and sell notes in the open market. These transactions may include short sales, stabilizing transactions and purchases to cover positions created by short sales. Short sales involve the sale by the underwriters of a greater number of notes than they are required to purchase in the offering. Stabilizing transactions consist of certain bids or purchases made for the purpose of preventing or retarding a decline in the market price of the notes while the offering is in progress.

The underwriters also may impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased notes sold by or for the account of such underwriter in stabilizing or short covering transactions.

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These activities by the underwriters, as well as other purchases by the underwriters for their own accounts, may stabilize, maintain or otherwise affect the market price of the notes. As a result, the price of the notes may be higher than the price that otherwise might exist in the open market. If these activities are commenced, they may be discontinued by the underwriters at any time. These transactions may be effected in the over-the-counter market or otherwise.

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a Relevant Member State), each underwriter, with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the Relevant Implementation Date), has not made and will not make an offer of notes to the public in that Relevant Member State prior to the publication of a prospectus in relation to the notes which has been approved by the competent authority in that Relevant Member State or, where appropriate, approved in another Relevant Member State and notified to the competent authority in that Relevant Member State, all in accordance with the Prospectus Directive, except that it may, with effect from and including the Relevant Implementation Date, make an offer of notes to the public in that Relevant Member State at any time:

(a) to legal entities which are authorised or regulated to operate in the financial markets or, if not so authorised or regulated, whose corporate purpose is solely to invest in securities;

(b) to any legal entity which has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than 43,000,000 and (3) an annual net turnover of more than 50,000,000, as shown in its last annual or consolidated accounts; or

(c) in any other circumstances which do not require the publication by the Issuer of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an offer of notes to the public in relation to any notes in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the notes to be offered so as to enable an investor to decide to purchase or subscribe the notes, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in that Member State and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each Relevant Member State.

Each Underwriter has represented and agreed that:

(a) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of section 21 of FSMA) to persons who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 or in circumstances in which section 21 of FSMA does not apply to the company; and

(b) it has complied with, and will comply with, all applicable provisions of FSMA with respect to anything done by it in relation to the notes in, from or otherwise involving the United Kingdom.

The notes may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to professional investors within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a prospectus within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the notes may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by,

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the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to notes which are or are intended to be disposed of only to persons outside Hong Kong or only to professional investors within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

The notes have not been and will not be registered under the Securities and Exchange Law of Japan (the Securities and Exchange Law) and each underwriter has agreed that it will not offer or sell any notes, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Securities and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the notes may not be circulated or distributed, nor may the notes be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the SFA), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the notes are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the notes under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

We do not intend to apply for the notes to be listed on any securities exchange other than the Irish Stock Exchange for trading on the Alternative Securities Market thereof or for the notes to be quoted on any quotation system. We cannot assure you that the notes will be approved for listing or such listing will be maintained. The underwriters have advised us that they currently intend to make a market in the notes. However, they are not obligated to do so and any market making may be discontinued by an underwriter at any time without notice. Accordingly, no assurance can be given as to the liquidity of, or the trading market for, the notes.

Buyers who purchase the notes from the underwriters may be required to pay stamp taxes and other charges in accordance with the laws and practice of the country of purchase in addition to the initial public offering price set forth on the cover of this prospectus.

We estimate that our share of the total expenses of the offering, excluding underwriting discounts and commissions, will be approximately $250,000. The underwriters have also agreed to reimburse us for up to $150,000 in expenses incurred by us in connection with this offering.

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act of 1933.

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The underwriters have from time to time provided, and in the future may provide, certain investment banking and financial advisory services to us and our affiliates, for which they have received, and in the future would receive, customary fees. In addition, affiliates of each of the underwriters listed in the table are lenders under our existing revolving bank credit facility. Amounts outstanding under our existing revolving bank credit facility will be repaid in connection with this offering. An affiliate of Lehman Brothers Inc. is a participant in a drilling business with us. We have each contributed approximately $25 million to this venture.

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission utilizing a shelf registration process for an immediate, delayed or continuous offering process as set forth in Rule 415 under the Securities Act. You should read this prospectus together with additional information described under Where You Can Find More Information. You should rely only on the information contained or incorporated by reference in this prospectus. We have not authorized anyone to provide you with different information. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this prospectus.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the SEC.

We incorporate by reference in this prospectus the following documents filed with the SEC pursuant to the Securities Exchange Act of 1934 (the Exchange Act):

- our Annual Report on Form 10-K for the fiscal year ended December 31, 2005;
- our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2006, June 30, 2006 and September 30, 2006; and
- our current reports on Form 8-K filed on November 1, 2005, January 10, 2006, January 18, 2006, January 26, 2006, January 30, 2006 (two reports of the same date), February 1, 2006, February 3, 2006, February 8, 2006, February 10, 2006, February 15, 2006 (two reports of the same date), February 21, 2006, February 24, 2006, February 28, 2006, March 8, 2006, March 22, 2006, April 7, 2006, April 21, 2006, May 2, 2006, May 8, 2006, May 31, 2006, June 6, 2006, June 8, 2006 (two reports of the same date), June 15, 2006 (three reports of the same date), June 27, 2006 (one such report as amended on July 24, 2006), June 30, 2006 (two reports of the same date), July 10, 2006, July 28, 2006, August 3, 2006, August 9, 2006, September 27, 2006, October 2, 2006, October 6, 2006, October 16, 2006, October 23, 2006, October 27, 2006, November 13, 2006, November 17, 2006, November 20, 2006 and November 21, 2006 (excluding any information furnished pursuant to Item 2.02 or Item 7.01 of any such current report on Form 8-K).

We also incorporate by reference any future filings made by us with the SEC under Sections 13(a), 13(c), 14, or 15(d) of the Exchange Act (excluding any information furnished pursuant to Item 2.02 or Item 7.01 of any such current report on Form 8-K that is filed in the future and is not deemed filed under the Exchange Act), until the underwriters have sold all of the notes.

The information incorporated by reference is an important part of this prospectus, and information that we file later with the SEC will automatically update and supersede this information as well as the information included in this prospectus.

You may read and copy any document we file with the SEC at the SEC public reference room located at:

100 F Street, N.E.

Room 1580

Washington, D.C. 20549

Please call the SEC at 1-800-SEC-0330 for further information on the public reference room and its copy charges. Our SEC filings are also available to the public on the SEC s web site at http://www.sec.gov and through the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005, on which our shares of common stock are traded.

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During the course of the offering and prior to sale, we invite each offeree of the notes to ask us questions concerning the terms and conditions of the offering and to obtain any additional information necessary to verify the accuracy of the information in this prospectus which is material to the offering to the extent that we possess such information or can acquire it without unreasonable effort or expense. You may obtain a copy of any or all of the documents summarized in this prospectus or incorporated by reference in this prospectus, without charge, by request directed to us at the following address and telephone number:

Jennifer M. Grigsby

Corporate Secretary

Chesapeake Energy Corporation

6100 North Western Avenue

Oklahoma City, Oklahoma 73118

Telephone: (405) 879-9225

corpsec@chkenergy.com

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FORWARD-LOOKING STATEMENTS

This prospectus contains or incorporates by reference forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and natural gas reserve estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expectations of closing and the impact of the pending committed acquisitions as described in this prospectus, 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 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;
- uncertainties inherent in estimating quantities of oil and natural gas reserves, projecting future rates of production and the timing of development expenditures;
- our ability to replace reserves and sustain production;
- uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities;
- the effect of oil and natural gas prices on our borrowing ability;
- unsuccessful exploration and development drilling;
- declines in the values 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 commodities price risk management activities;
- adverse effects of governmental and environmental regulation;
- losses possible from pending or future litigation;
- drilling and operating risks; and
- uncertainties and difficulties associated with the integration and operation of our recently acquired properties.

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

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LISTING AND GENERAL INFORMATION

Listing

We intend to apply to list the notes on the Irish Stock Exchange for trading on the Alternative Securities Market thereof in accordance with the rules of that exchange. In connection with such listing, we will appoint a listing agent.

Pursuant to the rules of the Irish Stock Exchange, we accept responsibility for the information contained in this prospectus. To the best of our knowledge and belief, the information contained in this prospectus is in accordance with the facts and does not omit anything likely to affect the import of such information. Information relating to each of the Guarantors was provided by the respective Guarantor.

For as long as the Notes are listed on the Irish Stock Exchange for trading on the Alternative Securities Market thereof and the rules of that exchange require, copies of the following documents may be inspected and obtained at the specific office of the Issuer and the Irish paying agent:

- our certificate of incorporation and by-laws and the certificates of incorporation and by-laws (or comparable organizational documents) of the Guarantors;
- our annual consolidated and interim financial statements; and
- the Indenture for the Notes (which includes the form of the Notes).

As long as the Notes are listed on the Irish Stock Exchange and the rules of the Irish Stock Exchange shall so require, we will maintain a paying and transfer agent in Ireland. We reserve the right to vary such appointment and we will publish notice of such change of appointment in a newspaper having a general circulation in Ireland.

We have appointed AIB/BNY Fund Management (Ireland) Limited as paying agent and transfer agent in Ireland and The Bank of New York, London Branch as principal paying agent, transfer agent and registrar to make payments on, and transfers of, the Notes. We reserve the right to vary such appointments.

We prepare audited consolidated annual financial statements according to U.S. GAAP. These annual financial statements are published in our annual report on Form 10-K and filed with the SEC. We do not prepare non-consolidated financial statements or financial statements for individual Guarantors. Our historical consolidated financial statements include the financial information of the Guarantors that are our subsidiaries.

So long as the Notes are listed on the Irish Stock Exchange for trading on the Alternative Securities Market thereof, the Notes will be freely transferable and negotiable in accordance with the rules of the Irish Stock Exchange.

Clearing Information

The Notes sold pursuant to the Securities Act have been accepted for clearance through the facilities of Euroclear and Clearstream. The Notes are represented by the Global Note with the ISIN of XS0273933902 and the Common Code of 027393390.

Legal Information

We are a corporation incorporated under the laws of Oklahoma on December 23, 1996. Our registered office is 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102. We have not been involved in any litigation, administrative proceeding or arbitration relating to claims or amounts which are material in the context of the issue of the Notes, and, to our knowledge, no such litigation, administrative proceeding or arbitration is pending or threatened.

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Guarantor Information

As of the date of closing of the offering of the Notes hereby, the Guarantors are expected to include:

Chesapeake Eagle Canada Corp., which is a corporation incorporated under the laws of New Brunswick, Canada on June 7, 2002 with a registered office at Suite 600, 570 Queen Street, P.O. Box 610, Fredericton, New Brunswick E3B 5A6;

Chesapeake Energy Louisiana Corporation, which is a corporation incorporated under the laws of Oklahoma on June 27, 1997 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Energy Marketing, Inc., which is a corporation incorporated under the laws of Oklahoma on December 15, 1993 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Operating, Inc., which is a corporation incorporated under the laws of Oklahoma on May 18, 1989 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake South Texas Corp., which is a corporation incorporated under the laws of Oklahoma on July 5, 2002 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Nomac Drilling Corporation, which is a corporation incorporated under the laws of Oklahoma on February 7, 2001 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Carmen Acquisition, L.L.C., which is a limited liability company formed under the laws of Oklahoma on January 29, 2001 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Acquisition, L.L.C., which is a limited liability company formed under the laws of Oklahoma on October 13, 1997 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Appalachia, L.L.C., which is a limited liability company formed under the laws of Oklahoma on October 10, 2005 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Land Company, L.L.C., which is a limited liability company formed under the laws of Oklahoma on December 29, 2004 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake ORC, L.L.C., which is a limited liability company formed under the laws of Oklahoma on January 28, 2003 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Royalty, L.L.C., which is a limited liability company formed under the laws of Oklahoma on September 30, 1998 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Gothic Production, L.L.C., which is a limited liability company formed under the laws of Oklahoma on March 26, 1998 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Hawg Hauling & Disposal, LLC, which is a limited liability company formed under the laws of Delaware on August 27, 2003 with a registered office at The Corporation Trust Company, 1209 Orange Street, Corporation Trust Center, Wilmington, Delaware 19801;

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Hodges Trucking Company, L.L.C., which is a limited liability company formed under the laws of Oklahoma on January 23, 1987 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Mayfield Processing, L.L.C., which is a limited liability company formed under the laws of Oklahoma on August 25, 2003 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

MC Mineral Company, L.L.C., which is a limited liability company formed under the laws of Oklahoma on April 21, 2003 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

W. W. Realty, L.L.C., which is a limited liability company formed under the laws of Oklahoma on April 3, 1990 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Exploration Limited Partnership, which is a limited partnership formed under the laws of Oklahoma on December 27, 1994 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Louisiana, L.P., which is a limited partnership formed under the laws of Oklahoma on May 20, 1997 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102;

Chesapeake Sigma, L.P., which is a limited partnership formed under the laws of Oklahoma on July 28, 2002 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102; and

MidCon Compression, L.P., which is a limited partnership formed under the laws of Oklahoma on September 15, 2003 with a registered office at 735 First National Bank, 120 North Robinson, Oklahoma City, Oklahoma 73102.

LEGAL MATTERS

The validity of the issuance of the notes and certain other legal matters will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. The underwriters are being represented by Cravath, Swaine & Moore LLP, New York, New York. Vinson & Elkins L.L.P. and Cravath, Swaine & Moore LLP will rely upon Commercial Law Group, P.C., Oklahoma City, Oklahoma, as to all matters of Oklahoma law.

EXPERTS

The financial statements as of December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005 and management s assessment of the effectiveness of internal control over financial reporting (which is included in Management s Report on Internal Control over Financial Reporting) as of December 31, 2005, included in this prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of Columbia Energy Resources, LLC as of December 31, 2004 and 2003 and for the year ended December 31, 2004 and the four months ended December 31, 2003, incorporated in this prospectus by reference from the current report on Form 8-K of Chesapeake Energy Corporation filed with the SEC on November 1, 2005, have been so incorporated in reliance on the report of Ernst & Young LLP,

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an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

Estimates of the oil and gas reserves of Chesapeake Energy Corporation and related future net cash flows and the present values thereof, included in Chesapeake s annual report on Form 10-K for the year ended December 31, 2005, were based in part upon reserve reports prepared by Netherland, Sewell & Associates, Inc., Schlumberger Data and Consulting Services, Lee Keeling and Associates, Inc., Ryder Scott Company, L.P., LaRoche Petroleum Consultants, Ltd., H.J. Gruy and Associates, Inc. and Miller and Lents, Ltd., independent petroleum engineers. We have incorporated these estimates in reliance on the authority of each such firm as experts in such matters.

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Annex A

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

(405) 848-8000

Registrant s telephone number, including area code

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

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

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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

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.

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:

	2005	December 31, 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		
			Annual
	Total	Limited	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 portion may be carried forward and may be used in addition to successive years annual limitation.

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

Title to Properties

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

Operating Hazards and Insurance

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

Chesapeake maintains a $50 million oil and gas lease operator policy that insures against certain sudden and accidental risks associated with drilling, completing and operating our wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $175 million comprehensive general liability umbrella policy and a $100 million pollution liability policy. We provide workers compensation insurance coverage to employees in all states in which we operate and we maintain a $1 million employment practice liability policy. While we believe these policies are customary in the industry, they do not provide complete coverage against all operating risks.

Facilities

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

Illinois: Chicago;

Kansas: Garden City;

Kentucky: Gray, Elkhorn City, Hueysville, Inez and Prestonburg;

Louisiana: Cheneyville and Shreveport;

New Mexico: Eunice and Hobbs;

New York: Hammondsport;

Oklahoma: Arkoma, Billings, El Reno, Kingfisher, Lindsay, Waynoka, Weatherford, Wilburton, Forgan and Sayre;

Tennessee: Egan;

Texas: Borger, Dumas, College Station, Midland, Cleburne, Goliad, Ozona, Tyler, Victoria and Zapata; and

West Virginia: Branchland, Buckhannon, Cedar Grove, Charleston, Clendenin, Kermit and Tad.

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Employees

Chesapeake had 2,885 employees as of December 31, 2005, which includes 429 employed by our drilling subsidiary, Nomac Drilling Corporation. As a result of the CNR acquisition, approximately 140 of our employees are covered by a collective bargaining agreement. We believe our employee relations are good.

Glossary of Oil and Gas Terms

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of gas equivalent.

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

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

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

Development Well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

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

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

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

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

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

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

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

Mbtu. One thousand btus.

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Mcf. One thousand cubic feet.

Mcfe. One thousand cubic feet of gas equivalent.

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

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Mmcfe. One million cubic feet of gas equivalent.

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

NYMEX. New York Mercantile Exchange.

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

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

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

Reserve Replacement. Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, 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 on page 107. 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.

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

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geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Undeveloped Location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

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

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

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

Tcf. One trillion cubic feet.

Tcfe. One trillion cubic feet of gas equivalent.

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

Working Interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

ITEM 1A. ***Risk Factors***

Our business has many risks. Any of the following factors could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes could decline. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

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

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

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

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Declines in oil and gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 92% of our reserves at December 31, 2005 are natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may limit our financial flexibility.

As of December 31, 2005, we had long-term indebtedness of approximately $5.5 billion, with $72.0 million drawn under our revolving bank credit facility. Our long-term indebtedness represented 47% of our total book capitalization at December 31, 2005. As of March 10, 2006, we had approximately $402 million 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 peer companies that have less debt;

the covenants contained in the agreements governing our outstanding indebtedness and future indebtedness may limit our ability to borrow additional funds, pay dividends and make certain investments and may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;

additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes may have higher costs and more restrictive covenants;

changes in the credit ratings of our debt may negatively affect the cost, terms, conditions and availability of future financing, and lower ratings will increase the interest rate and fees we pay on our revolving bank credit facility; and

we may be more vulnerable to general adverse economic and industry conditions.

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

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

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

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

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

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

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations, our revolving bank credit facility and debt and equity issuances. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of oil and gas, and our success in developing, acquiring and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves. If our cash flow from operations is not sufficient to 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 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 35% of our total estimated proved reserves (by volume) at December 31, 2005 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 24% from 2006 to 2007. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves.

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

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

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

At December 31, 2005, approximately 35% 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 $1.8 billion in 2006. 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, 2005 present value is based on weighted average oil and natural gas wellhead prices of $56.41 per barrel of oil and $8.76 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 gas industry in general will affect the accuracy of the 10% discount factor.

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

Our recent growth is due in part to acquisitions of exploration and production companies, producing properties and undeveloped leasehold. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves,

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

We were not entitled to contractual indemnification for the majority of pre-closing liabilities, including environmental liabilities, in our recent acquisition of CNR. We acquired CNR on an as is basis with very limited remedies for breaches of representations and warranties. We might incur significant liabilities relating to CNR in the future which we have not yet identified or cannot quantify at this time.

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

Significant acquisitions present operational and administrative challenges that may prove more difficult than anticipated. The failure to consolidate functions and integrate procedures, personnel and operations in an effective and timely manner may adversely affect our business and results of operations, at least temporarily. Significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. To the extent that we acquire properties substantially different from the properties in our primary operating areas or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as in our prior acquisitions. As a result of our recent acquisition of CNR, we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York. We have not previously developed or explored for oil and natural gas in this part of the U.S.

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

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

- 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

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- 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 gas properties. Under this method, all such costs (for both productive and nonproductive properties) are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, these capitalized costs are subject to a ceiling test which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved oil and gas reserves discounted at 10% plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the prices for oil and gas at that date, adjusted for the impact of derivatives accounted for as cash flow hedges. A significant decline in oil and gas prices from current levels, or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

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

In order to manage our exposure to price volatility in marketing our oil and gas, we enter into oil and gas price risk management arrangements for a portion of our expected production. Commodity price hedging may limit the prices we actually realize and therefore reduce oil and gas revenues in the future. The fair value of our oil and gas derivative instruments outstanding as of December 31, 2005 was a liability of approximately $945.8 million. In addition, our commodity price risk management transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

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

Some of our commodity price and interest rate risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2005, we were required to post a total of $50 million of collateral with our counterparties through letters of credit issued under our bank credit facility with respect to commodity price and financial risk management transactions. As of March 10, 2006, we were required to post $50 million of collateral with our counterparties through letters of credit. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and highly volatile natural gas and oil prices.

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

Our amended and restated revolving bank credit facility limits our borrowings to the lesser of the borrowing base (currently $2.5 billion) and the commitment (currently $2.0 billion). The borrowing base is determined periodically at the discretion of the banks and is based in part on oil and gas prices. Additionally, some of our indentures contain covenants limiting our ability to incur indebtedness in addition to that incurred under our bank credit facility. These indentures limit our ability to incur additional indebtedness unless we meet one of two alternative tests. The first alternative is based on our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and gas reserves as of the end of each year. The second alternative is based on the ratio of our adjusted consolidated EBITDA (as defined in the relevant indentures) to our adjusted consolidated interest expense over a trailing twelve-month period. As of the date of this report, we are permitted to incur significant additional indebtedness under both of these debt incurrence tests. Lower oil and gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

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

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

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

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

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

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, 2005:		
First Quarter	$ 23.65	$ 15.06
Second Quarter	24.00	17.74
Third Quarter	38.98	22.90
Fourth Quarter	40.20	26.59
Year ended December 31, 2004:		
First Quarter	$ 13.98	$ 11.70
Second Quarter	15.05	12.68
Third Quarter	16.24	13.69
Fourth Quarter	18.31	15.17

At March 10, 2006, there were 1,473 holders of record of our common stock and approximately 322,000 beneficial owners.

Dividends

The following table sets forth the amount of dividends per share declared on Chesapeake common stock during 2005 and 2004:

	2005	**2004**
First Quarter	$ 0.045	$ 0.035
Second Quarter	0.050	0.045
Third Quarter	0.050	0.045
Fourth Quarter	0.050	0.045

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

Several of the indentures governing our outstanding senior notes contain restrictions on our ability to declare and pay cash dividends. Under these indentures, we may not pay any cash dividends on our common or preferred stock if an event of default has occurred, if we have not met one of the two debt incurrence tests described in the indentures, or if immediately after giving effect to the dividend payment, we have paid total dividends and made other restricted payments in excess of the permitted amounts. As of December 31, 2005, our coverage ratio for purposes of the debt incurrence test under the relevant indentures was 5.45 to 1, compared to 2.25 to 1 required in our indentures. Our adjusted consolidated net tangible assets under the relevant indentures exceeded 200% of our total indebtedness, as required in our indentures, by more than $5.2 billion.

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The following table presents information about repurchases of our common stock during the three months ended December 31, 2005:

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, 2005 through October 31, 2005	28,227	$ 32.461		
November 1, 2005 through November 30, 2005	26,596	$ 29.890		
December 1, 2005 through December 31, 2005	22,952	$ 31.965		
Total	77,775	$ 31.435		

(a) Includes 75,224 shares purchased in the open market for the matching contributions we make to our 401(k) plans and the surrender to the company of 2,551 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 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, 2005, 2004, 2003, 2002 and 2001. The data are derived from our audited consolidated financial statements revised to reflect the reclassification of certain items. In addition to changes in the annual average prices for oil and gas and increased production from drilling activity, significant acquisitions in recent years also impacted comparability between years. See Notes 11 and 13 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,				
	2005	2004	2003	2002	2001
	($ in thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822	$ 568,187	$ 820,318
Oil and gas marketing sales	1,392,705	773,092	420,610	170,315	148,733
Total revenues	4,665,290	2,709,268	1,717,432	738,502	969,051
Operating costs:					
Production expenses	316,956	204,821	137,583	98,191	75,374
Production taxes	207,898	103,931	77,893	30,101	33,010
General and administrative expenses	64,272	37,045	23,753	17,618	14,449
Oil and gas marketing expenses	1,358,003	755,314	410,288	165,736	144,373
Oil and gas depreciation, depletion and amortization	894,035	582,137	369,465	221,189	172,902
Depreciation and amortization of other assets	50,966	29,185	16,793	14,009	8,663
Provision for legal settlements		4,500	6,402		
Total operating costs	2,892,130	1,716,933	1,042,177	546,844	448,771
Income from operations	1,773,160	992,335	675,255	191,658	520,280
Other income (expense):					
Interest and other income	10,452	4,476	2,827	7,340	2,877
Interest expense	(219,800)	(167,328)	(154,356)	(112,031)	(98,321)
Loss on repurchases or exchanges of Chesapeake debt	(70,419)	(24,557)	(20,759)	(2,626)	(76,667)
Loss on investment in Seven Seas Petroleum, Inc.			(2,015)	(17,201)	
Impairments of investments in securities					(10,079)
Gain on sale of Canadian subsidiary					27,000
Gothic standby credit facility costs					(3,392)
Total other income (expense)	(279,767)	(187,409)	(174,303)	(124,518)	(158,582)
Income before income taxes and cumulative effect of accounting change	1,493,393	804,926	500,952	67,140	361,698
Income tax expense (benefit):					
Current			5,000	(1,822)	3,565
Deferred	545,091	289,771	185,360	28,676	140,727
Total income tax expense	545,091	289,771	190,360	26,854	144,292
Net income before cumulative effect of accounting change, net of tax	948,302	515,155	310,592	40,286	217,406
Cumulative effect of accounting change, net of income taxes of $1,464,000			2,389		
Net Income	948,302	515,155	312,981	40,286	217,406
Preferred stock dividends	(41,813)	(39,506)	(22,469)	(10,117)	(2,050)
Loss on conversion/exchange of preferred stock	(26,874)	(36,678)			

Net income available to common shareholders	$ 879,615	$ 438,971	$ 290,512	$ 30,169	$ 215,356
Earnings per common share basic:					
Income before cumulative effect of accounting change	$ 2.73	$ 1.73	$ 1.36	$ 0.18	$ 1.33
Cumulative effect of accounting change			0.02		
	$ 2.73	$ 1.73	$ 1.38	$ 0.18	$ 1.33
Earnings per common share assuming dilution:					
Income before cumulative effect of accounting change	$ 2.51	$ 1.53	$ 1.20	$ 0.17	$ 1.25
Cumulative effect of accounting change			0.01		
	$ 2.51	$ 1.53	$ 1.21	$ 0.17	$ 1.25
Cash dividends declared per common share	$ 0.195	$ 0.170	$ 0.135	$ 0.060	$

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	Years Ended December 31,				
	2005	2004	2003	2002	2001
	($ in thousands, except per share data)				
Cash Flow Data:					
Cash provided by operating activities	$ 2,406,888	$ 1,432,274	$ 938,907	$ 428,797	$ 478,098
Cash used in investing activities	7,017,494	3,381,204	2,077,217	779,745	670,105
Cash provided by financing activities	4,663,737	1,915,245	931,254	480,991	310,146
Effect of exchange rate changes on cash					(545)
Balance Sheet Data (at end of period):					
Total assets	$ 16,118,462	$ 8,244,509	$ 4,572,291	$ 2,875,608	$ 2,286,768
Long-term debt, net of current maturities	5,489,742	3,075,109	2,057,713	1,651,198	1,329,453
Stockholders equity	6,174,323	3,162,883	1,732,810	907,875	767,407

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

Financial Data

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

	December 31,		
	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 (a)	$ 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 (b)	$ 0.47	$ 0.45	$ 0.55
Interest Expense ($ in thousands):			

Interest expense	$ 226,330	$ 162,781	$ 151,676
Interest rate derivatives realized (gains) losses	(4,945)	(791)	(3,859)
Interest rate derivatives unrealized (gains) losses	(1,585)	5,338	6,539
Total interest expense	$ 219,800	$ 167,328	$ 154,356
Net Wells Drilled	816	546	456
Net Producing Wells as of the End of Period	16,985	8,058	5,873

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

We manage our business as three separate segments, an exploration and production segment, a marketing segment and a service operations segment which is comprised of our wholly owned drilling subsidiary. 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 2005, 2004 and 2003 and our assets as of December 31, 2005, 2004 and 2003.

Executive Summary

Chesapeake is the second largest independent producer of natural gas in the United States and we own interests in approximately 30,600 producing oil and gas wells. 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 in the eastern U.S. Our most important operating area has historically been the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At December 31, 2005, 51% of our proved reserves were located in the Mid-Continent. 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 the emerging Fayetteville Shale play in Arkansas. As a result of our recent acquisition of Columbia Energy Resources, LLC and its subsidiaries, including Columbia Natural Resources, LLC (CNR) as described below, we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York.

Chesapeake attributes its strong organic growth rates during 2005 and in the past five years to management s early recognition that oil and gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry people, land and seismic. During the past five years, Chesapeake has invested more than $3.0 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be the largest inventories of onshore leasehold (8.5 million net acres) and 3-D seismic (11.6 million acres) in the U.S. On this leasehold, the company has identified more than a 10-year drilling inventory of approximately 28,000 drilling locations.

In addition, Chesapeake has significantly strengthened its technical capabilities during the past five years by increasing its land, geoscience and engineering staff by 400% to over 600 employees. Today, the company has more than 3,300 employees, of which approximately 70% work in the company s E&P operations and 30% work in the company s oilfield service operations.

Oil and natural gas production for 2005 was 468.6 bcfe, an increase of 106.0 bcfe, or 29% over the 362.6 bcfe produced in 2004. We have increased our production for 16 consecutive years and 18 consecutive quarters. During these 18 quarters, Chesapeake s U.S. production has increased 262% for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 33%.

In addition to increased oil and natural gas production, the prices we received were higher in 2005 than in 2004. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $6.90 per mcfe in 2005 compared to $5.23 per mcfe in 2004. The increase in prices resulted in an increase in revenue of $782.2 million, and increased production resulted in an increase in revenue of $554.0 million, for a total increase in revenue of $1.336 billion (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist thereby contributing to relatively high wellhead price realizations for our production.

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During 2005, Chesapeake drilled 902 (686 net) operated wells and participated in another 1,066 (130 net) wells operated by other companies. The company s drilling success rate was 98% for company-operated wells and 95% for non-operated wells. During 2005, Chesapeake invested $1.511 billion in operated wells (using an average of 73 operated rigs), $309 million in non-operated wells (using an average of approximately 66 non-operated rigs) and $362 million in acquiring new 3-D seismic data and new leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $4.9 billion during 2005 (including amounts paid for unproved leasehold and excluding $252 million of deferred taxes in connection with certain corporate acquisitions). We expect to continue replacing reserves through the drillbit and acquisitions, although the timing and magnitude of future additions are uncertain.

Chesapeake began 2005 with estimated proved reserves of 4.902 tcfe and ended the year with 7.521 tcfe, an increase of 2.619 tcfe, or 53%. During 2005, we replaced 468.6 bcfe of production with an estimated 3.088 tcfe of new proved reserves, for a reserve replacement rate of 659%. This compares to reserve replacement of 578% and 459% for 2004 and 2003, respectively. 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), or 34% of the total increase. Reserve replacement through acquisitions was 2.041 tcfe, or 436% of production, or 66% of the total increase. Our annual decline rate on producing properties is projected to be 24% from 2006 to 2007, 16% from 2007 to 2008, 13% from 2008 to 2009, 11% from 2009 to 2010 and 10% from 2010 to 2011. Our percentage of proved undeveloped reserve additions to total proved reserve additions was approximately 36% in 2005, 56% in 2004 and 35% in 2003. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2005 will begin producing within the next five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within a year.

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 working capital deficit and its prepaid sales agreement and hedging positions. 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.

In anticipation of today s tight drilling rig market, Chesapeake began making a series of investments in drilling rigs in 2001. In that year, Chesapeake formed its 100% owned drilling rig subsidiary, Nomac Drilling Corporation, with an investment of $26 million to build and refurbish five drilling rigs. Chesapeake has invested a total of $123 million in Nomac s 19 operating rigs, invested another $26 million in 25 rigs that Nomac is currently building, and budgeted an additional $191 million for completion of these rigs.

In addition to Nomac, Chesapeake has also made four other major drilling rig investments. The first of these was its ownership of approximately 17% of the common stock of Pioneer Drilling Company (Pioneer), which we began acquiring in 2003. The company recently sold its Pioneer stock, realizing proceeds of $159 million and a pre-tax gain of $116 million that it will recognize in the 2006 first quarter. Chesapeake re-invested the Pioneer proceeds to acquire 13 rigs from privately held Martex Drilling Company, L.L.P. for $150 million.

Chesapeake has invested $43 million in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns 45% and 49%, respectively. DHS owns ten drilling rigs and has three more rigs on order. Mountain owns one drilling rig and has ordered another nine rigs for delivery in 2006 and 2007. Chesapeake s drilling rig investments have served as a partial hedge to rising service costs and have also provided competitive advantages in making acquisitions and in developing its own leasehold on a more timely basis.

As of December 31, 2005, the company s 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. During 2005, we received net proceeds of $5.252 billion through issuances of $1.380 billion of preferred equity, $1.025 billion of common equity, and $2.990 billion principal amount of senior notes. We issued 18.7 million shares of common stock in exchange for outstanding shares of our 4.125% and 5.0% (Series 2003) preferred stock and upon conversions of our 6.0% preferred stock. Additionally, we purchased and retired $564.4 million principal amount of outstanding senior notes during 2005. As a result of our debt transactions during 2005, we have extended the average maturity of our long-term debt to over 10 years and have lowered our average interest rate to approximately 6.3%.

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

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. 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.

Liquidity and Capital Resources

Sources of Liquidity and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our drilling capital expenditures in 2006. Our budget for drilling, land and seismic activities during 2006 is currently between $3.0 billion and $3.2 billion. We believe this level of exploration and development will be sufficient to increase our reserves in 2006 and achieve our goal of a 10% to 20% increase in production over 2005 production (inclusive of acquisitions completed or scheduled to close in 2006 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2006). However, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, dividends, debt repayment or other general corporate purposes in 2006.

Cash provided by operating activities was $2.407 billion in 2005, compared to $1.432 billion in 2004 and $938.9 million in 2003. The $975 million increase from 2004 to 2005 and the $493.1 million increase from 2003 to 2004 were primarily due to higher realized prices and higher volumes of oil and gas production. We expect that 2006 production volumes will be higher than in 2005 and that cash provided by operating activities in 2006 will exceed 2005 levels. While a precipitous decline in gas prices in 2006 would affect the amount of cash flow that would be generated from operations, we have 63% of our expected oil production in 2006 hedged at an average NYMEX price of $61.02 per barrel of oil and 71% (excluding the hedges assumed in the CNR acquisition and certain collars and options) of our expected natural gas production in 2006 hedged at an average NYMEX price of $9.43 per mcf. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our 2006 production. Depending on changes in oil and gas futures markets and management s view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. At December 31, 2005 and March 10, 2006, we had $50 million of letters of credit securing our performance of hedging contracts. To mitigate the liquidity impact of those collateral requirements, we have negotiated caps on the amount of collateral that we might be required to post with seven of our counterparties. All of our existing commodity hedges that are not under our

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secured hedge facilities (described below under *Contractual Obligations*) are with these counterparties and the maximum amount of collateral that we would be required to post with them is no more than $230 million in the aggregate.

A significant source of liquidity is our $2.0 billion syndicated revolving bank credit facility which matures in February 2011. At March 10, 2006, there was $1.5 billion of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $5.682 billion and repaid $5.669 billion in 2005, we borrowed $2.160 billion and repaid $2.101 billion in 2004 and we borrowed and repaid $738 million in 2003 under our bank credit facility. We incurred $4.7 million, $2.2 million and $2.5 million of financing costs related to our revolving bank credit facility in 2005, 2004 and 2003, respectively, as a result of amendments to the credit facility agreement. Also during 2005, we repaid the remaining credit facility balance of $96.1 million assumed in the CNR acquisition.

We believe that our available cash, cash provided by operating activities and funds available under our revolving bank credit facility will be sufficient to fund our operating, interest and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future.

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

The following table reflects the proceeds from sales of securities we issued in 2005, 2004 and 2003 ($ in millions):

	2005		2004		2003	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Unsecured senior notes guaranteed by subsidiaries	$ 2,300.0	$ 2,251.3	$ 1,200.0	$ 1,166.0	$ 500.0	$ 485.4
Contingent convertible unsecured senior notes	690.0	673.3				
Convertible preferred stock	1,380.0	1,341.5	313.3	304.9	402.5	390.4
Common stock	1,024.6	985.8	650.0	624.2	186.3	177.4
Total	$ 5,394.6	$ 5,251.9	$ 2,163.3	$ 2,095.1	$ 1,088.8	$ 1,053.2

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

We paid dividends on our common stock of $60.5 million, $38.9 million and $27.3 million in 2005, 2004 and 2003, respectively, and we paid dividends on our preferred stock of $31.5 million, $40.9 million and $20.9 million in 2005, 2004 and 2003, respectively. We received $21.6 million, $12.0 million and $9.3 million from the exercise of employee and director stock options and warrants in 2005, 2004 and 2003, respectively. We paid $4.0 million and $2.1 million to purchase treasury stock in 2005 and 2003 to fund our matching contributions to our 401(k) make-up plan. There were no treasury stock purchases made in 2004.

In 2005, we paid $11.6 million to settle derivative liabilities assumed from CNR.

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Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $61.2 million, $88.3 million and $28.3 million in 2005, 2004 and 2003, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake. The following table shows our redemption, purchases and exchanges of senior notes for 2005, 2004 and 2003 ($ 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	$ 19.0	$ 1.2	$	$	$ 20.2
8.125% Senior Notes due 2011	245.4	17.3	0.7		263.4
9.0% Senior Notes due 2012	300.0	41.4	0.8		342.2
	$ 564.4	$ 59.9	$ 1.5	$	$ 625.8
For the Year Ended December 31, 2004:					
8.375% Senior Notes due 2008	$ 190.8	$ 16.1	$ 0.5	$	$ 207.4
7.875% Senior Notes due 2004	42.1				42.1
8.5% Senior Notes due 2012	4.3	0.2			4.5
8.125% Senior Notes due 2011 (b)	482.8		62.1	(534.2)	10.7
	$ 720.0	$ 16.3	$ 62.6	$ (534.2)	$ 264.7
For the Year Ended December 31, 2003:					
8.5% Senior Notes due 2012	$ 106.4	$ 6.7	$	$	$ 113.1
8.5% Senior Notes due 2012 (c)	32.0		1.5	(33.5)	
8.375% Senior Notes due 2008 (d)	27.9		1.6	(29.5)	
8.375 Senior Notes due 2008 and 8.125% Senior Notes due 2011 (e)	22.9		0.8	(23.7)	
8.375% Senior Notes due 2008 and 8.125% Senior Notes due 2011 (f)	61.2		2.6	(63.8)	
	$ 250.4	$ 6.7	$ 6.5	$ (150.5)	$ 113.1

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

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Cash used in investing activities increased to $6.921 billion in 2005, compared to $3.381 billion in 2004 and $2.077 billion in 2003. The following table shows our capital expenditures during these years ($ in millions):

	2005	2004	2003
Acquisitions of oil and gas companies, proved and unproved properties, net of cash acquired	$ 3,925.5	$ 1,914.7	$ 1,261.3
Exploration and development of oil and gas properties	2,371.9	1,276.3	727.2
Additions to buildings and other fixed assets	417.5	126.7	71.5
Additions to investments	135.0	37.0	30.8
Additions to drilling equipment	66.8	23.1	1.2
Deposits for acquisitions	35.0	16.3	13.3
Total	$ 6,951.7	$ 3,394.1	$ 2,105.3

Through divestitures of oil and gas properties, we received $9.8 million in 2005, $12.0 million in 2004 and $22.2 million, in 2003. Sales of other assets and investments in securities of other companies provided $20.4 million, $0.9 million and $5.8 million of cash in 2005, 2004 and 2003, respectively.

Our accounts receivable are primarily from purchasers of oil and natural gas ($615.4 million at December 31, 2005) and exploration and production companies which own interests in properties we operate ($84.8 million at December 31, 2005). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

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

Investing and Financing Transactions

The following table describes investing transactions that we completed in 2005 ($ in millions):

Acquisition	Location	Amount
Columbia Natural Resources, LLC	Appalachian Basin	$ 2,200(a)
BRG Petroleum Corporation	Mid-Continent and Ark-La-Tex	325(b)
Hallwood Energy, III L.P.	Barnett Shale	250(c)
Laredo Energy II, L.L.C.	South Texas	228
Houston-based oil and gas company	Texas Gulf Coast/South Texas	202
Pecos Production Company	Permian	198
Laredo II Partners	Texas Gulf Coast/South Texas	139
Corpus Christi-based oil and gas company	Ark-La-Tex	95
Dallas-based oil and gas company	Ark-La-Tex	85
Midland-based oil and gas company	Permian	38
Other	Various	372(d)
		$ 4,132

(a) Includes $175 million related to gathering systems which was allocated to other property and equipment.
(b) We paid $16.3 million of the purchase amount in 2004.
(c) Includes $15 million related to gathering systems which was allocated to other property and equipment.

(d) In 2005, we paid the remaining $57 million of the purchase price related to an acquisition transaction with Hallwood Energy Corporation in the fourth quarter of 2004.

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During 2004 and continuing in 2005, we have taken several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over ten years with an average interest rate of approximately 6.3%. Maintaining a debt-to-total-capitalization ratio below 50% and reducing debt per mcfe of proved reserves remain key goals of our business strategy.

We completed the following significant financing transactions in 2005:

First Quarter 2005

Amended our revolving bank credit facility to increase the committed borrowing base to $1.25 billion and extended the maturity of the facility to January 2010.

Completed a private purchase of $11.0 million of our 8.375% Senior Notes due 2008 for $12.0 million (including a premium of $0.8 million).

Second Quarter 2005

Completed private offerings of $600 million principal amount of 6.625% Senior Notes due 2016 and 4,600,000 shares of 5.0% cumulative convertible preferred stock having a liquidation preference of $100 per share. Net proceeds of approximately $1.032 billion from these transactions were used to finance acquisitions totaling $459 million that closed in the second quarter of 2005 and to repay debt incurred under our revolving bank credit facility to temporarily finance the BRG and the Laredo acquisitions completed in the first quarter.

Completed a private placement of $600 million of 6.25% Senior Notes due 2018. Net proceeds of approximately $596.4 million were used to fund our purchases in June 2005 of $237.8 million of our 8.125% Senior Notes due 2011 for $255.3 million (including a premium of $16.8 million and transaction costs of $0.7 million) and $298.9 million of our 9.0% Senior Notes due 2012 for $341.0 million (including a premium of $41.3 million and transaction costs of $0.8 million) pursuant to tender offers for the 8.125% and 9.0% Senior Notes.

Completed a private exchange of 45,000 shares of our outstanding 4.125% cumulative convertible preferred stock for 2,911,250 shares of common stock. No cash was received or paid in connection with this transaction.

Third Quarter 2005

Completed cash tender offers for our 8.125% Senior Notes due 2011 and 9.0% Senior Notes due 2012. Approximately $0.3 million was used to purchase $0.1 million of 8.125% Senior Notes due 2011 and $0.2 million of 9.0% Senior Notes due 2012. Together with the amounts acquired in June 2005, we acquired a total of $237.9 million principal amount of 8.125% Senior Notes due 2011 and $299.1 million principal amount of 9.0% Senior Notes due 2012, representing 96.9% and 99.7%, respectively, of the amounts outstanding, in the tender offers, which expired on July 6, 2005. We redeemed the remaining $7.5 million of 8.125% and $0.9 million of 9.0% Senior Notes for $9.1 million (including a premium of $0.6 million) on August 17, 2005 based on the make-whole redemption provisions in the indentures.

Completed a number of transactions whereby we exchanged 133,675 shares of our 4.125% cumulative convertible preferred stock for 8,529,758 shares of our common stock. No cash was received or paid in connection with these transactions.

Completed a number of transactions whereby we exchanged 697,724 shares of our 5.0% (Series 2003) cumulative convertible preferred stock for 4,354,439 shares of our common stock. No cash was received or paid in connection with these transactions.

Completed a private placement of $600 million of 6.5% Senior Notes due 2017. Net proceeds of approximately $584.6 million were used to repay amounts outstanding under our revolving bank credit facility which resulted from acquisitions completed in the third quarter.

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Completed public offerings of 3,450,000 shares of 4.5% cumulative convertible preferred stock having a liquidation preference of $100 per share and 9,200,000 shares of common stock at $32.72 per share. Net proceeds from both offerings of approximately $624.6 million were used to repay amounts outstanding under our revolving bank credit facility which resulted from acquisitions completed in the third quarter.

Fourth Quarter 2005

Completed private offerings of $500 million of 6.875% Senior Notes due 2020, $690 million of 2.75% Contingent Convertible Senior Notes due 2035 and 5,750,000 shares of 5.00% cumulative convertible preferred stock having a liquidation preference of $100 per share. Net proceeds of approximately $1.718 billion along with cash on hand and borrowings under our credit facility were used to fund the CNR acquisition.

Completed a public offering of 23 million shares of common stock at $31.46 per share. Net proceeds of approximately $696.4 million were used to repay outstanding borrowings under our revolving bank credit facility which were incurred to temporarily finance the CNR acquisition.

Completed a number of transactions whereby we exchanged 45,515 shares of our 4.125% cumulative convertible preferred stock for 2,880,873 shares of our common stock. No cash was received or paid in connection with these transactions.

Completed an exchange of 1,330 shares of 5.0% (Series 2003) cumulative convertible preferred stock for 8,281 shares of common stock. No cash was received or paid in connection with these transactions.

Contractual Obligations

We currently have a $2.0 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006. As of December 31, 2005, we had $72.0 million of outstanding borrowings under this facility and had utilized $53.0 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies from 0.125% to 0.30% according to our senior unsecured long-term debt ratings. Currently the annual commitment fee is 0.25%. 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, purchase or redeem our capital stock, make investments or loans, and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. At December 31, 2005, our indebtedness to total capitalization ratio was 0.48 to 1 and our indebtedness to EBITDA ratio was 2.34 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($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.

Some of our commodity price and financial risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations exceed certain levels. As of December 31, 2005, we were required to post $50 million of collateral in the form of

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letters of credit with respect to such derivative transactions. These collateral requirements were $50 million as of March 10, 2005. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and fluctuations in natural gas and oil prices and interest rates. We currently have arrangements with five of our counterparties, with which we have outstanding transactions, that limit the amount of collateral that we would be required to post with them to no more than $230 million in the aggregate.

We have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for these facilities is May 2010. 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. One of the hedging facilities is subject to an annual fee of 0.30% of the maximum total capacity and each of them has a 1.0% exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of December 31, 2005, the fair market value of the natural gas and oil hedging transactions was a liability of $92.9 million under one of the facilities and a liability of $10.9 million under the other facility. As of March 10, 2006, the fair market value of the same transactions was an asset of approximately $100 million and $400 million, respectively. 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 gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly-owned domestic subsidiaries. Our revolving bank credit facility and secured hedge 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 hedge facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

In addition to outstanding revolving bank credit facility borrowings discussed above, as of December 31, 2005, senior notes represented approximately $5.4 billion of our long-term debt and consisted of the following ($ in thousands):

7.5% Senior Notes due 2013	$ 363,823
7.0% Senior Notes due 2014	300,000
7.5% Senior Notes due 2014	300,000
7.75% Senior Notes due 2015	300,408
6.375% Senior Notes due 2015	600,000
6.625% Senior Notes due 2016	600,000
6.875% Senior Notes due 2016	670,437
6.5% Senior Notes due 2017	600,000
6.25% Senior Notes due 2018	600,000
6.875% Senior Notes due 2020	500,000
2.75% Contingent Convertible Senior Notes due 2035	690,000
Discount on senior notes	(95,577)
Discount for interest rate derivatives	(11,349)
	$ 5,417,742

No scheduled principal payments are required on any of the senior notes until 2013, when $363.8 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes.

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As of December 31, 2005 and currently, debt ratings for the senior notes are Ba2 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (stable outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly-owned domestic subsidiaries guarantee the notes. The indentures (other than the indentures issued after June 2005) contain covenants limiting our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of December 31, 2005, we estimate that secured commercial bank indebtedness of approximately $3.6 billion could have been incurred under the most restrictive indenture covenant.

The table below summarizes our contractual obligations as of December 31, 2005 ($ in thousands)

		Payments Due By Period			
		Less than	1-3	3-5	More than
Contractual Obligations	**Total**	**1 Year**	**Years**	**Years**	**5 years**
Long-term debt obligations	$ 5,596,668	$	$	$	$ 5,596,668
Capital lease obligations	8,979	3,370	4,219	1,390	
Operating lease obligations	13,759	4,124	6,310	2,623	702
Purchase obligations (a)	662,551	387,290	167,375	12,419	95,467
Standby letters of credit	57,609	57,609			
Other long-term obligations					
Total contractual cash obligations	$ 6,339,566	$ 452,393	$ 177,904	$ 16,432	$ 5,692,837

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

Hedging Activities

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. Executive management is involved in all risk management activities and the Board of Directors reviews the company s hedging program at every Board meeting. We believe we have sufficient internal controls to prevent unauthorized hedging. As of December 31, 2005, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. Item 7A Quantitative and Qualitative Disclosures About Market Risk contains a description of each of these instruments. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

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

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Realized gains and losses from our oil and gas derivatives resulted in a net decrease in oil and gas sales of $401.7 million, or $0.86, per mcfe in 2005, a net decrease of $154.9 million, or $0.43, per mcfe in 2004 and a net decrease of $17.4 million, or $0.06, per mcfe in 2003. Oil and gas sales also include changes in the fair value of oil and gas derivatives that do not qualify as cash flow hedges under SFAS 133, as well as gains (losses) on ineffectiveness of instruments designated as cash flow hedges. Unrealized gains (losses) included in oil and gas sales in 2005, 2004 and 2003 were $41.1 million, $40.9 million and $10.5 million, respectively. Included in these unrealized gains (losses) are gains (losses) on ineffectiveness of cash flow hedges of ($76.3) million in 2005, ($8.2) million in 2004 and ($9.2) million in 2003.

Changes in the fair value of oil and gas derivative instruments designated as cash flow hedges, to the extent effective in offsetting cash flows attributable to the hedged commodities, and locked-in gains and losses of derivative contracts are recorded in accumulated other comprehensive income until being transferred to earnings in the month of related production. These unrealized losses, net of related tax effects, totaled $270.7 million, $4.4 million and $20.3 million as of December 31, 2005, 2004, and 2003, respectively. Based upon the market prices at December 31, 2005, we expect to transfer to earnings approximately $153.8 million of the loss included in the balance of accumulated other comprehensive income during the next 12 months when the transactions actually occur. A detailed explanation of accounting for oil and gas derivatives under SFAS 133 appears under Application of Critical Accounting Policies Hedging elsewhere in this Item 7.

The fair values of our oil and gas derivative instruments are recorded on our consolidated balance sheet as assets or liabilities. The estimated fair values of our oil and gas derivative instruments (including derivatives acquired from CNR) as of December 31, 2005 and 2004 are provided below:

	December 31, 2005	December 31, 2004
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ (1,047,094)	$ 57,073
Gas basis protection swaps	307,308	122,287
Fixed-price gas cap-swaps	(161,056)	(48,761)
Fixed-price gas counter-swaps	37,785	4,654
Gas call options (a)	(21,461)	(5,793)
Fixed-price gas collars	(9,374)	(5,573)
Fixed-price gas locked swaps	(34,229)	(77,299)
Floating-price gas swaps	2,607	
Fixed-price oil swaps	(16,936)	
Fixed-price oil cap-swaps	(3,364)	(8,238)
Estimated fair value	$ (945,814)	$ 38,350

(a) After adjusting for the remaining $23.0 million and $3.2 million premium paid to Chesapeake by the counterparty, the cumulative unrealized loss related to these call options as of December 31, 2005 and 2004 was $1.6 million and $2.6 million, respectively.

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

	2005	December 31, 2004 ($ in thousands)	2003
Fair value of contracts outstanding, as of January 1	$ 38,350	$ (44,988)	$ (14,533)
Change in fair value of contracts during the period	(771,076)	(69,927)	(31,078)
Contracts realized or otherwise settled during the period	401,684	154,901	17,389
Fair value of new contracts when entered into during the period	(614,772)	(5,369)	(16,766)
Fair value of contracts when closed during the period		3,733	
Fair value of contracts outstanding, as of December 31	$ (945,814)	$ 38,350	$ (44,988)

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 of interest rate derivatives are recorded on the consolidated balance sheets as assets (liabilities) and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2005, the following interest rate swaps were used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value Gain (Loss) ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,734)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	$ (5,133)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	$ (5,327)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	$ (5,004)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	$ (1,344)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	$ (3,240)
October 2005 January 2016	$ 200,000,000	6.625%	6 month LIBOR plus 129 basis points	$ 282

In January 2006, we closed the interest rate swap on our 6.625% Senior Notes for $1.0 million. Subsequent to December 31, 2005, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points
March 2006 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 125.5 basis points

In 2005, we closed various interest rate swaps for gains totaling $7.1 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

In March 2004, Chesapeake entered into an interest rate swap which required Chesapeake to pay a fixed rate of 8.68% while the counterparty paid Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. On March 15, 2005, we elected to terminate the interest rate swap and paid $31.8 million to the counterparty.

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Results of Operations

General. For the year ended December 31, 2005, Chesapeake had net income of $948.3 million, or $2.51 per diluted common share, on total revenues of $4.665 billion. This compares to net income of $515.2 million, or $1.53 per diluted common share, on total revenues of $2.709 billion during the year ended December 31, 2004, and net income of $313.0 million, or $1.21 per diluted common share, on total revenues of $1.717 billion during the year ended December 31, 2003. The 2005 net income includes, on a pre-tax basis, a $70.4 million loss on repurchased debt and $42.7 million in net unrealized gains on oil and gas and interest rate derivatives. The 2004 net income includes, on a pre-tax basis, a $24.6 million loss on repurchased debt, a $4.5 million provision for legal settlements and $35.5 million in net unrealized gains on oil and gas and interest rate derivatives. The 2003 net income includes, on a pre-tax basis, a $20.8 million loss on repurchased debt, a $6.4 million provision for legal settlements, $4.0 million in net unrealized losses on oil and gas and interest rate derivatives, and a $2.0 million impairment of our investment in Seven Seas Petroleum Inc.

Oil and Gas Sales. During 2005, oil and gas sales were $3.273 billion compared to $1.936 billion in 2004 and $1.297 billion in 2003. In 2005, Chesapeake produced and sold 468.6 bcfe at a weighted average price of $6.90 per mcfe, compared to 362.6 bcfe in 2004 at a weighted average price of $5.23 per mcfe, and 268.4 bcfe in 2003 at a weighted average price of $4.79 per mcfe (weighted average prices for all years discussed exclude the effect of unrealized gains or (losses) on derivatives of $41.1 million, $40.9 million and $10.5 million in 2005, 2004 and 2003, respectively). The increase in prices in 2005 resulted in an increase in revenue of $782 million and increased production resulted in a $554 million increase, for a total increase in revenues of $1.336 billion (excluding unrealized gains or losses on oil and gas derivatives). The increase in production from period to period was due to the combination of production growth from drilling as well as acquisitions completed during those periods.

For 2005, we realized an average price per barrel of oil of $47.77, compared to $28.33 in 2004 and $25.85 in 2003 (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 $6.78, $5.29 and $4.85 in 2005, 2004 and 2003, respectively. Realized gains or losses from our oil and gas derivatives resulted in a net decrease in oil and gas revenues of $401.7 million or $0.86 per mcfe in 2005, a net decrease of $154.9 million or $0.43 per mcfe in 2004 and a net decrease of $17.4 million or $0.06 per mcfe in 2003.

A change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming 2005 production levels, a change of $0.10 per mcf of gas sold would result in an increase or decrease in revenues and cash flow of approximately $42.2 million and $39.5 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 $7.7 million and $7.2 million, respectively, without considering the effect of hedging activities.

The following table shows our production by region for 2005, 2004 and 2003:

	Years Ended December 31,					
	2005		2004		2003	
	Mmcfe	Percent	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	297,773	64%	268,459	74%	233,559	87%
South Texas and Texas Gulf Coast	63,852	13	42,427	12	15,546	6
Ark-La-Tex and Barnett Shale	58,116	12	19,640	5	7,776	3
Permian	40,207	9	29,468	8	8,496	3
Appalachia	5,878	1				
Other	2,751	1	2,599	1	2,979	1
Total Production	468,577	100%	362,593	100%	268,356	100%

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Natural gas production represented approximately 90% of our total production volume on an equivalent basis in 2005, compared to 89% in 2004 and 90% in 2003.

Oil and Gas Marketing Sales. Chesapeake realized $1.393 billion in oil and gas marketing sales to third parties in 2005, with corresponding oil and gas marketing expenses of $1.358 billion, for a net margin of $35 million. Marketing activities are substantially for third parties who are owners in Chesapeake operated wells. This compares to sales of $773 million and $421 million, expenses of $755 million and $410 million, and margins of $18 million and $11 million in 2004 and 2003, respectively. In 2005 and 2004, Chesapeake realized an increase in volumes and prices related to oil and gas marketing sales as compared to the previous year.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $317.0 million in 2005, compared to $204.8 million and $137.6 million in 2004 and 2003, respectively. On a unit-of-production basis, production expenses were $0.68 per mcfe in 2005 compared to $0.56 and $0.51 per mcfe in 2004 and 2003, respectively. The increase in 2005 was primarily due to higher third-party field service costs, energy costs and personnel costs. We expect that production expenses per mcfe produced for 2006 will range from $0.77 to $0.82.

Production Taxes. Production taxes were $207.9 million in 2005 compared to $103.9 million in 2004 and $77.9 million in 2003. On a unit-of-production basis, production taxes were $0.44 per mcfe in 2005 compared to $0.29 per mcfe in both 2004 and 2003. The $104.0 million increase in production taxes in 2005 is due primarily to approximately 106.0 bcfe of increased production and the increase of $2.10 per mcfe in sales price (excluding gains or losses on derivatives). Included in 2004 is a credit of $6.8 million, or $0.02 per mcfe, related to certain Oklahoma severance tax abatements for the period July 2003 through December 2003. In April 2004, the Oklahoma Tax Commission concluded that a pre-determined oil and gas price cap for 2003 sales had not been exceeded (on a statewide basis) and notified the company that it was eligible to receive certain severance tax abatements for the period from July 1, 2003 through June 30, 2004. The company had previously estimated that the average oil and gas sales prices in Oklahoma (on a statewide basis) could exceed the price cap, and did not reflect the benefit from these potential severance tax abatements until the first quarter of 2004. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes per mcfe to range from $0.41 to $0.46 during 2006 based on NYMEX prices of $54.00 per barrel of oil and natural gas wellhead prices ranging from $7.50 to $8.50 per mcfe produced.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties (see Note 11 of notes to consolidated financial statements), were $64.3 million in 2005, $37.0 million in 2004 and $23.8 million in 2003. General and administrative expenses were $0.14, $0.10 and $0.09 per mcfe for 2005, 2004 and 2003, respectively. The increase in 2005 and 2004 was the result of the company s overall growth. This growth has resulted in a substantial increase in employees and related costs. Included in general and administrative expenses is stock-based compensation of $15.3 million in 2005, $4.8 million in 2004 and $0.9 million in 2003. During 2005, 3.9 million shares of restricted stock, net of forfeitures, were granted to employees. The cost of all outstanding restricted shares is amortized over a four-year period which resulted in the recognition of $23.3 million of stock-based compensation costs during 2005. Of this amount, $12.6 million was reflected in general and administrative expense, and the remaining $10.7 million was capitalized to oil and gas properties. Chesapeake did not issue restricted stock awards prior to 2004. Additionally, we recognized $3.9 million, $0.6 million and $0.9 million in stock-based compensation expense in 2005, 2004 and 2003, respectively, as a result of modifications made to previously issued stock options. Of the $3.9 million recognized in 2005, $1.2 million was capitalized to oil and gas properties. Stock-based compensation was $0.03 per mcfe for 2005 and $0.01 per mcfe for 2004. We anticipate that general and administrative expenses for 2006 will be between $0.22 and $0.26 per mcfe produced including stock based compensation ranging from $0.08 and $0.10 per mcfe produced.

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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 $102.2 million, $51.7 million and $35.5 million of internal costs (excluding stock-based compensation) in 2005, 2004 and 2003, respectively, directly related to our oil and gas property acquisition, exploration and development efforts.

Provision for Legal Settlements. In 2004, we recorded a provision for legal settlement of $4.5 million related to various litigation incidental to our business operations. In 2003, we recorded a $6.4 million provision related to the settlement of a class-action lawsuit with certain Oklahoma royalty owners.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $894.0 million, $582.1 million and $369.5 million during 2005, 2004 and 2003, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.91, $1.61 and $1.38 in 2005, 2004 and 2003, respectively. The increase in the average rate from $1.61 in 2004 to $1.91 in 2005 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 2006 DD&A rate to be between $2.15 and $2.20 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $51.0 million in 2005, compared to $29.2 million in 2004 and $16.8 million in 2003. The increase in 2005 and 2004 was primarily the result of higher depreciation costs resulting from the acquisition of various gathering facilities, compression equipment, construction of new buildings at our corporate headquarters complex and at various field office locations and the purchase of additional information technology equipment and software in 2005 and 2004. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect 2006 depreciation and amortization of other assets to be between $0.14 and $0.16 per mcfe produced.

Interest and Other Income. Interest and other income was $10.5 million, $4.5 million and $2.8 million in 2005, 2004 and 2003, respectively. The 2005 income consisted of $3.0 million of interest income, $1.8 million of income related to equity investments, and $5.7 million of miscellaneous income. The 2004 income consisted of $2.1 million of interest income, $0.8 million of income related to earnings on investments, and $1.6 million of miscellaneous income. The 2003 income consisted of $1.0 million of interest income, a $0.4 million loss related to an equity investment, a $0.6 million gain on the final settlement of the sale of our Canadian subsidiary and $1.6 million of miscellaneous income.

Interest Expense. Interest expense increased to $219.8 million in 2005 compared to $167.3 million in 2004 and $154.4 million in 2003 as follows:

	Years Ended December 31,		
	2005	2004	2003
	($ in millions)		
Interest expense on senior notes and revolving bank credit facility	$ 299.6	$ 194.5	$ 163.2
Capitalized interest	(79.0)	(36.2)	(13.0)
Amortization of loan discount	5.7	4.5	1.6
Unrealized (gain) loss on interest rate derivatives	(1.6)	5.3	6.5
Realized gain on interest rate derivatives	(4.9)	(0.8)	(3.9)
Total interest expense	$ 219.8	$ 167.3	$ 154.4
Average long-term borrowings	$ 3,948	$ 2,428	$ 1,932

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

Interest expense, excluding unrealized (gains) losses on derivatives and net of amounts capitalized, was $0.47 per mcfe in 2005 compared to $0.45 per mcfe in 2004 and $0.55 per mcfe in 2003. We expect interest expense for 2006 to be between $0.52 and $0.57 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Investment in Seven Seas. In 2003, we reduced the carrying value of our 2001 investment in securities of Seven Seas Petroleum Inc. to zero by recording an impairment of $2.0 million. We recovered approximately $5.5 million on this investment in 2003 and recorded an impairment of $17.2 million in 2002.

Loss on Repurchases or Exchanges of Debt. During the past three years we have repurchased or exchanged Chesapeake debt and incurred losses in connection with these transactions. We entered into these transactions in order to re-finance a portion of our long-term debt at a lower rate of interest. The following table shows the losses related to these transactions for 2005, 2004 and 2003, respectively ($ in millions):

	Notes	**Loss on Repurchases/Exchanges**		
For the Year Ended December 31, 2005:	**Retired**	**Premium**	**Other (a)**	**Total**
8.375% Senior Notes due 2008	$ 19.0	$ 1.2	$ 0.1	$ 1.3
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 564.4	$ 59.9	$ 10.5	$ 70.4
For the Year Ended December 31, 2004:				
8.375% Senior Notes due 2008	$ 190.8	$ 16.1	$ 1.5	$ 17.6
8.5% Senior Notes due 2012	4.3	0.2	0.7	0.9
8.125% Senior Notes due 2011	482.8		6.0	6.0
	$ 677.9	$ 16.3	$ 8.2	$ 24.5
For the Year Ended December 31, 2003:				
8.5% Senior Notes due 2012	$ 106.4	$ 6.7	$ 14.1(b)	$ 20.8

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

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

Income Tax Expense. 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. 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. During 2003 and 2001, we determined that it was more likely than not that $4.4 million and $2.4 million, respectively, of the deferred tax assets related to Louisiana net operating losses would not be realized and we recorded a valuation allowance equal to such amounts during those years. In 2004, we acquired Louisiana oil and gas properties which resulted in us determining that it was more likely than not that the

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$6.8 million of deferred tax assets related to Louisiana net operating losses would be realized. Therefore, the $6.8 million valuation allowance was reversed at December 31, 2004 as part of the recording of the purchase of these assets. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

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

Loss on Conversion/Exchange of Preferred Stock. Loss on conversion/exchange of preferred stock was $26.9 million in 2005 compared to $36.7 million in 2004. The 2005 loss was the result of private exchanges of $224.2 million of our 4.125% cumulative convertible preferred stock for 14.3 million shares of common stock and private exchanges of $69.9 million of our 5.0% (Series 2003) cumulative convertible preferred stock for 4.4 million shares of common stock. The 2004 loss was the result of a private exchange of $30.0 million of our 6.0% cumulative convertible preferred stock for 3.2 million shares of common stock and a public exchange of $194.8 million of our 6.0% cumulative convertible preferred stock for 20.8 million shares of common stock. The loss on the exchanges represented the excess of the fair value of the common stock issued over the fair value of the securities issuable pursuant to the original conversion terms. We also incurred $1.2 million in transaction costs related to the public exchange.

Application of Critical Accounting Policies

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

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

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

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

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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 the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control.

Due to the volatility of oil and natural gas prices and, to a lesser extent, interest rates, the company s financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2005, 2004 and 2003, the net market value of our derivatives was a liability of $968.3 million, an asset of $2.5 million and a liability of $75.4 million, respectively. The derivatives that we acquired in our CNR acquisition represented $661.4 million of the liability at December 31, 2005. With respect to our derivatives held as of December 31, 2005, an increase or decrease in natural gas prices of $0.10 per mmbtu would decrease or increase the estimated fair value of our derivatives by approximately $136 million. An increase or decrease in crude oil prices of $1.00 per barrel would decrease or increase the estimated fair value of our derivatives by approximately $8 million.

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

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If

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we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly.

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

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

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

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

As of December 31, 2005, approximately 78% 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 2005 year-end reserve evaluation is included under Oil and 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.

The volatility of oil and natural gas prices and the impact of revisions to reserve estimates can have a significant impact on the company s financial condition and results of operations. Our oil and gas depreciation, depletion and amortization rates have increased from $1.38 per mcfe in 2003 to $1.91 per mcfe in 2005 reflecting the impact of increases in prices and finding costs during these periods. As of December 31, 2005, a decrease in natural gas prices of $0.10 per mcf and a decrease in oil prices of $1.00 per barrel would reduce the company s estimated proved reserves by 3.5 bcfe and by 1.1 bcfe, respectively, as a result of economic truncation of the expected producing lives of some properties.

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

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

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

If (a) natural gas and oil prices were to decrease significantly below present levels (and if such decreases were considered other than temporary), (b) exploration, drilling and operating costs were to increase significantly beyond current levels, or (c) we were confronted with any other significantly negative evidence pertaining to our ability to realize our NOL carryforwards prior to their expiration, we may be required to provide a valuation allowance against our deferred tax assets. As of December 31, 2005, we had deferred tax assets of $726.5 million.

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

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

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

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We believe that the consideration we have paid for our 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 business combinations, 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, 2005, we had accrued accounts receivable from our two co-founders, CEO Aubrey K. McClendon and former COO, Tom L. Ward, of $6.4 million and $6.4 million, respectively, representing joint interest billings from December 2005 which were invoiced and paid in January 2006. Since Chesapeake was founded in 1989, Messrs. McClendon and Ward have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billings to them are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the Founder Well Participation Program, approved by our shareholders in June 2005, Messrs. McClendon and Ward may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake, but they are not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors 30 days prior to the start of each calendar year. Their participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of their participation. In addition, the company is reimbursed for the cost of its leasehold acquired by Messrs. McClendon and Ward as a result of their well participation. As a result of the resignation of Mr. Ward on February 10, 2006, his participation in the Founder Well Participation Program will expire on August 10, 2006, which is also the expiration date of non-competition covenants applicable to Mr. Ward.

As disclosed in Note 8 of the notes to our consolidated financial statements in Item 8, in 2005, Chesapeake had revenues of $851.4 million from oil and gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

During 2005, 2004 and 2003, we paid legal fees of $1.2 million, $1.1 million and $2.1 million, respectively, for legal services provided by a law firm of which a former director is a member.

Recently Issued Accounting Standards

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

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This statement is effective as of the beginning of the annual reporting period that begins after June 15, 2005. Since the issuance of SFAS 123(R), three FASB Staff Positions (FSPs) have been issued regarding SFAS 123(R). These FSPs, FSP FAS 123(R)-1 *Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R)*, FSP FAS 123(R)-2 *Practical Accommodation to the Application of Grant Date as Defined in FASB Statement No. 123(R),* and FSP FAS 123(R)-3 *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards* will be applicable upon the initial adoption of SFAS 123(R).

Chesapeake will implement SFAS 123(R) in the first quarter of 2006 and the Black-Scholes option pricing model will be used to value the stock options as of the grant date. Based on the stock options outstanding and unvested at December 31, 2005 and our current intention to limit future awards of stock options, we do not believe the new accounting requirement will have a significant impact on future results of operations.

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In March 2005, the FASB issued FASB Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations*. FIN 47 specifies the accounting treatment for conditional asset retirement obligations under the provisions of SFAS No. 143. FIN 47 is effective no later than the end of the fiscal year ending after December 15, 2005. We adopted this statement effective December 31, 2005. Implementation of FIN 47 did not have a material effect on our financial statements.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3.* SFAS 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but we do not currently expect SFAS 154 to have a material impact on our financial statements.

In June 2005, the EITF reached a consensus on Issue No. 04-10, *Determining Whether to Aggregate Operating Segments That Do Not Meet the Quantitative Thresholds*. EITF Issue 04-10 confirmed that operating segments that do not meet the quantitative thresholds can be aggregated only if aggregation is consistent with the objective and basic principles of SFAS 131, *Disclosure about Segments of an Enterprise and Related Information*. The consensus in this issue should be applied for fiscal years ending after September 30, 2005, and the corresponding information for earlier periods, including interim periods, should be restated unless it is impractical to do so. The adoption of EITF Issue 04-10 is not expected to have a material impact on our disclosures.

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

Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and gas reserve estimates, planned capital expenditures, the drilling of oil and gas wells and future acquisitions, expected oil and gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations 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 Items 1. and 2. of this report and include:

- the volatility of oil and gas prices,
- our level of indebtedness,
- the strength and financial resources of our competitors,
- the availability of capital on an economic basis to fund reserve replacement costs,

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- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of oil and gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and 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 gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- lower oil and gas prices could negatively affect our ability to borrow, and
- drilling and operating risks.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this 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 Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2005, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

- For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

Basis protection swaps are arrangements that guarantee a price differential for oil or gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

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

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

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

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

Chesapeake enters into derivatives from time to time for the purpose of converting a fixed price gas sales contract to a floating price. We refer to these contracts as floating price swaps. For a floating price swap, Chesapeake receives a floating market price from the counterparty and pays a fixed price.

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

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or gas from a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual prices we receive for much of our gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future gas price differentials. As of December 31, 2005, the fair value of our basis protection swaps was $307.3 million. Currently, our basis protection swaps cover approximately 24% of our anticipated gas production remaining in 2006, 24% in 2007, 20% in 2008, and 14% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Realized gains (losses) included in oil and gas sales were ($401.7) million, ($154.9) million and ($17.4) million in 2005, 2004 and 2003, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales were $41.1 million, $40.9 million and $10.5 million, in 2005, 2004 and 2003, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as unrealized gains (losses). We recorded a gain (loss) on ineffectiveness of ($76.3) million, ($8.2) million and ($9.2) million in 2005, 2004 and 2003, respectively.

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As of December 31, 2005, we had the following open oil and gas derivative instruments designed to hedge a portion of our oil and gas production for periods after December 2005 (excluding derivatives acquired from CNR):

	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 Received ($ in thousands)	Fair Value at December 31, 2005 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
1Q 2006	93,030,000	10.60				Yes		(34,043)
2Q 2006	61,880,000	9.03				Yes		(80,285)
3Q 2006	62,560,000	9.02				Yes		(87,205)
4Q 2006	52,155,000	9.42				Yes		(80,961)
1Q 2007	37,800,000	10.72				Yes		(40,253)
2Q 2007	20,020,000	9.04				Yes		(9,700)
3Q 2007	20,240,000	9.04				Yes		(10,526)
4Q 2007	20,240,000	9.56				Yes		(11,900)
1Q 2008	14,105,000	10.28				Yes		(9,199)
2Q 2008	14,105,000	7.94				Yes		(10,122)
3Q 2008	14,260,000	7.96				Yes		(10,140)
4Q 2008	14,260,000	8.48				Yes		(10,492)
Basis Protection Swaps:								
1Q 2006	34,200,000				(0.33)	No		66,338
2Q 2006	30,940,000				(0.31)	No		21,892
3Q 2006	31,280,000				(0.31)	No		17,380
4Q 2006	33,720,000				(0.32)	No		22,268
1Q 2007	32,850,000				(0.29)	No		24,990
2Q 2007	34,125,000				(0.35)	No		23,208
3Q 2007	34,500,000				(0.35)	No		18,471
4Q 2007	35,720,000				(0.32)	No		20,078
1Q 2008	33,215,000				(0.29)	No		19,800
2Q 2008	26,845,000				(0.25)	No		17,689
3Q 2008	27,140,000				(0.25)	No		14,136
4Q 2008	31,410,000				(0.28)	No		12,716
1Q 2009	26,100,000				(0.32)	No		9,076
2Q 2009	20,020,000				(0.28)	No		8,026
3Q 2009	20,240,000				(0.28)	No		5,505
4Q 2009	20,240,000				(0.28)	No		5,735
Cap-Swaps:								
1Q 2006	7,200,000	7.11	5.06			No		(28,331)
2Q 2006	11,830,000	6.84	5.13			No		(40,761)
3Q 2006	11,960,000	6.85	5.13			No		(42,622)
4Q 2006	11,960,000	6.89	5.13			No		(49,342)
Counter Swaps:								
1Q 2006	(1,800,000)	(6.19)				No		9,267
2Q 2006	(1,820,000)	(5.35)				No		9,062
3Q 2006	(1,840,000)	(5.33)				No		9,353
4Q 2006	(1,840,000)	(5.50)				No		10,103
Call Options:								
1Q 2006	1,800,000			12.50		No	1,890	(821)
2Q 2006	1,820,000			12.50		No	1,911	(781)
3Q 2006	1,840,000			12.50		No	1,932	(1,348)
4Q 2006	1,840,000			12.50		No	1,932	(2,408)
1Q 2007	1,800,000			12.50		No	1,890	(3,559)
2Q 2007	1,820,000			12.50		No	1,911	(1,285)
3Q 2007	1,840,000			12.50		No	1,932	(1,423)
4Q 2007	1,840,000			12.50		No	1,932	(2,371)
1Q 2008	1,820,000			12.50		No	1,911	(3,754)

2Q 2008	1,820,000	12.50	No	1,911	(893)
3Q 2008	1,840,000	12.50	No	1,932	(1,043)
4Q 2008	1,840,000	12.50	No	1,932	(1,775)

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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 Received ($ in thousands)	Fair Value at December 31, 2005 ($ in thousands)
Collars:								
1Q 2006	180,000		6.00	9.70		Yes		(270)
Locked Swaps:								
1Q 2006	6,300,000					No		(7,598)
2Q 2006	6,370,000					No		(5,199)
3Q 2006	6,440,000					No		(5,099)
4Q 2006	6,440,000					No		(4,706)
1Q 2007	6,300,000					No		(4,789)
2Q 2007	6,370,000					No		(2,517)
3Q 2007	6,440,000					No		(2,049)
4Q 2007	6,440,000					No		(2,272)
Floating-Price Swaps:								
1Q 2006	(2,700,000)	(7.96)				No		2,607
Total Natural Gas							23,016	(264,142)
Oil (bbls):								
Swaps:								
1Q 2006	900,000	60.00				Yes		(1,739)
2Q 2006	880,000	59.88				Yes		(2,760)
3Q 2006	828,000	60.16				Yes		(2,858)
4Q 2006	828,000	59.78				Yes		(3,415)
1Q 2007	360,000	57.13				Yes		(2,495)
2Q 2007	91,000	51.04				Yes		(1,200)
3Q 2007	92,000	50.56				Yes		(1,233)
4Q 2007	92,000	50.11				Yes		(1,236)
Cap-Swaps:								
1Q 2006	135,000	57.82	40.67			No		(565)
2Q 2006	136,500	57.82	40.67			No		(825)
3Q 2006	138,000	57.82	40.67			No		(1,057)
4Q 2006	92,000	56.53	40.00			No		(917)
Total Oil								(20,300)
Total Natural Gas and Oil							$ 23,016	$ (284,442)

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, 2005.

Based upon the market prices at December 31, 2005, we expect to transfer approximately $153.8 million (net of income taxes) of the loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of December 31, 2005 are expected to mature by December 31, 2009.

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

	December 31,		
	2005	2004	2003
		($ in thousands)	
Fair value of contracts outstanding, as of January 1	$ 38,350	$ (44,988)	$ (14,533)
Change in fair value of contracts during the period	(771,076)	(69,927)	(31,078)
Contracts realized or otherwise settled during the period	401,684	154,901	17,389
Fair value of new contracts when entered into during the period	(614,772)	(5,369)	(16,766)
Fair value of contracts when closed during the period		3,733	
Fair value of contracts outstanding, as of December 31	$ (945,814)	$ 38,350	$ (44,988)

The change in the fair value of our derivative instruments since January 1, 2005 resulted mainly from an increase in oil and 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 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.

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. 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 is 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 will result in adjustments to our oil and gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and 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 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 have hedged the production volumes listed below 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 will be reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

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The following details the CNR derivatives we have assumed:

	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, 2005 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
1Q 2006	7,872,500	4.91			Yes	(50,693)
2Q 2006	10,510,500	4.86			Yes	(56,501)
3Q 2006	10,626,000	4.86			Yes	(57,355)
4Q 2006	10,626,000	4.86			Yes	(62,483)
1Q 2007	10,350,000	4.82			Yes	(68,401)
2Q 2007	10,465,000	4.82			Yes	(46,158)
3Q 2007	10,580,000	4.82			Yes	(46,442)
4Q 2007	10,580,000	4.82			Yes	(51,557)
1Q 2008	9,555,000	4.68			Yes	(53,954)
2Q 2008	9,555,000	4.68			Yes	(33,892)
3Q 2008	9,660,000	4.68			Yes	(33,999)
4Q 2008	9,660,000	4.66			Yes	(38,487)
1Q 2009	4,500,000	5.18			Yes	(18,772)
2Q 2009	4,550,000	5.18			Yes	(10,450)
3Q 2009	4,600,000	5.18			Yes	(10,508)
4Q 2009	4,600,000	5.18			Yes	(12,616)
Total						(652,268)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(3,380)
2Q 2009	910,000		4.50	6.00	Yes	(1,754)
3Q 2009	920,000		4.50	6.00	Yes	(1,773)
4Q 2009	920,000		4.50	6.00	Yes	(2,197)
Total						(9,104)
Total Natural Gas						$ (661,372)

In connection with the November 14, 2005 acquisition of Columbia Natural Resources, LLC (CNR), Chesapeake assumed obligations under forward gas sales agreements with Mahonia II Limited (Mahonia) to deliver a total of 8.9 bcf of natural gas to Mahonia through February 2006. As of December 31, 2005, the remaining 4.25 bcf of gas scheduled to be delivered under this contract has been recorded as a $60.9 million current accrued liability, based on the fair value of the delivery commitment at the date of acquisition.

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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, 2005, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity							
	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt fixed-rate (a)	$	$	$	$	$	$ 5,524.7	$ 5,524.7	$ 5,582.4
Average interest rate						6.3%	6.3%	6.3%
Long-term debt variable rate	$	$	$	$	$	$ 72.0	$ 72.0	$ 72.0
Average interest rate						7.3%	7.3%	7.3%

(a) This amount does not include the discount included in long-term debt of ($95.6) million and the discount for interest rate swaps of ($11.3) 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 of interest rate derivatives are recorded on the consolidated balance sheets as assets (liabilities) and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

As of December 31, 2005, the following interest rate swaps were used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value Gain (Loss) ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,734)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	$ (5,133)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	$ (5,327)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	$ (5,004)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	$ (1,344)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	$ (3,240)
October 2005 January 2016	$ 200,000,000	6.625%	6 month LIBOR plus 129 basis points	$ 282

In January 2006, we closed the interest rate swap on our 6.625% Senior Notes for $1.0 million. Subsequent to December 31, 2005, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional	Floating Rate

		Amount	
January 2006	January 2016	$ 250,000,000	6 month LIBOR plus 129 basis points
March 2006	January 2016	$ 250,000,000	6 month LIBOR plus 120 basis points
March 2006	August 2017	$ 250,000,000	6 month LIBOR plus 125.5 basis points

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In 2005, we closed various interest rate swaps for gains totaling $7.1 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

In March 2004, Chesapeake entered into an interest rate swap which required Chesapeake to pay a fixed rate of 8.68% while the counterparty paid Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. On March 15, 2005, we elected to terminate the interest rate swap and paid $31.8 million to the counterparty.

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

INDEX TO FINANCIAL STATEMENTS

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.

Our evaluation of and conclusion on the effectiveness of internal control over financial reporting excludes Columbia Energy Resources, LLC, which we acquired in a purchase business combination on November 14, 2005. The acquisition of Columbia Energy Resources, LLC accounted for approximately twenty percent of our total assets at December 31, 2005, and contributed approximately two percent of our total revenue in fiscal 2005. See Note 13 for additional information regarding the acquisition.

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, 2005.

Our management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears herein.

Aubrey K. McClendon

Chairman and Chief Executive Officer

Marcus C. Rowland

Executive Vice President and Chief Financial Officer

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders

of Chesapeake Energy Corporation:

We have completed integrated audits of Chesapeake Energy Corporation s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

Internal control over financial reporting

Also, in our opinion, management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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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.

As described in Management s Report on Internal Control Over Financial Reporting, management has excluded Columbia Energy Resources, LLC from its assessment of internal control over financial reporting as of December 31, 2005 because it was acquired by the Company in a purchase business combination in November 2005. We have also excluded Columbia Energy Resources, LLC from our audit of internal control over financial reporting. Columbia Energy Resources, LLC is a wholly-owned subsidiary whose total assets and total revenues represent twenty percent and two percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2005.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma

March 13, 2006

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 60,027	$ 6,896
Accounts receivable:		
Oil and gas sales	615,382	347,081
Joint interest, net of allowances of $4,904,000 and $4,648,000, respectively	84,765	68,220
Related parties	12,839	8,286
Other	78,208	35,781
Deferred income tax asset	234,592	18,068
Short-term derivative instruments	10,503	51,061
Inventory and other	87,081	32,147
Total Current Assets	1,183,397	567,540
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	15,880,919	9,451,413
Unevaluated properties	1,739,095	761,785
Less: accumulated depreciation, depletion and amortization of oil and gas properties	(3,945,703)	(3,057,742)
Total oil and gas properties, at cost based on full-cost accounting	13,674,311	7,155,456
Other property and equipment	750,083	324,495
Drilling rigs	116,133	49,375
Less: accumulated depreciation and amortization of other property, equipment and drilling rigs	(128,640)	(84,942)
Total Property and Equipment	14,411,887	7,444,384
OTHER ASSETS:		
Investment in Pioneer Drilling Company	138,095	65,950
Other investments	159,348	26,793
Long-term derivative instruments	78,860	44,169
Other assets	146,875	95,673
Total Other Assets	523,178	232,585
TOTAL ASSETS	$ 16,118,462	$ 8,244,509

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	December 31, 2005	December 31, 2004
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 516,792	$ 367,176
Short-term derivative instruments	577,681	91,414
Other accrued liabilities	364,501	222,029
Revenues and royalties due others	394,693	216,820
Accrued interest	110,421	66,514
Total Current Liabilities	1,964,088	963,953
LONG-TERM LIABILITIES:		
Long-term debt, net	5,489,742	3,075,109
Deferred income tax liability	1,804,978	933,873
Asset retirement obligation	156,593	73,718
Long-term derivative instruments	479,996	1,296
Revenues and royalties due others	22,585	17,007
Other liabilities	26,157	16,670
Total Long-Term Liabilities	7,980,051	4,117,673
CONTINGENCIES AND COMMITMENTS (Note 4)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 99,310 and 103,110 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $4,965,500 and $5,155,500	4,966	5,156
5.00% cumulative convertible preferred stock (Series 2003), 1,025,946 and 1,725,000 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $102,594,600 and $172,500,000	102,595	172,500
4.125% cumulative convertible preferred stock, 89,060 and 313,250 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $89,060,000 and $313,250,000	89,060	313,250
5.00% cumulative convertible preferred stock (Series 2005), 4,600,000 and 0 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $460,000,000	460,000	
4.50% cumulative convertible preferred stock, 3,450,000 and 0 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $345,000,000	345,000	
5.00% cumulative convertible preferred stock (Series 2005B), 5,750,000 and 0 shares issued and outstanding as of December 31, 2005 and 2004, respectively, entitled in liquidation to $575,000,000	575,000	
Common Stock, $.01 par value, 500,000,000 shares authorized, 375,510,521 and 316,940,784 shares issued December 31, 2005 and 2004, respectively	3,755	3,169
Paid-in capital	3,803,312	2,440,105
Retained earnings	1,100,841	262,987
Accumulated other comprehensive income (loss), net of tax of $112,071,000 and ($11,489,000), respectively	(194,972)	20,425
Unearned compensation	(89,242)	(32,618)
Less: treasury stock, at cost; 5,320,816 and 5,072,121 common shares as of December 31, 2005 and 2004, respectively	(25,992)	(22,091)
Total Stockholders Equity	6,174,323	3,162,883

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 16,118,462	$ 8,244,509

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,		
	2005	**2004**	**2003**
	($ in thousands, except per share data)		
REVENUES:			
Oil and gas sales	$ 3,272,585	$ 1,936,176	$ 1,296,822
Oil and gas marketing sales	1,392,705	773,092	420,610
Total Revenues	4,665,290	2,709,268	1,717,432
OPERATING COSTS:			
Production expenses	316,956	204,821	137,583
Production taxes	207,898	103,931	77,893
General and administrative expenses	64,272	37,045	23,753
Oil and gas marketing expenses	1,358,003	755,314	410,288
Oil and gas depreciation, depletion and amortization	894,035	582,137	369,465
Depreciation and amortization of other assets	50,966	29,185	16,793
Provision for legal settlements		4,500	6,402
Total Operating Costs	2,892,130	1,716,933	1,042,177
INCOME FROM OPERATIONS	1,773,160	992,335	675,255
OTHER INCOME (EXPENSE):			
Interest and other income	10,452	4,476	2,827
Interest expense	(219,800)	(167,328)	(154,356)
Loss on repurchases or exchanges of Chesapeake debt	(70,419)	(24,557)	(20,759)
Loss on investment in Seven Seas Petroleum, Inc.			(2,015)
Total Other Income (Expense)	(279,767)	(187,409)	(174,303)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	1,493,393	804,926	500,952
INCOME TAX EXPENSE:			
Current			5,000
Deferred	545,091	289,771	185,360
Total Income Tax Expense	545,091	289,771	190,360
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	948,302	515,155	310,592
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF INCOME TAXES OF $1,464,000			2,389
NET INCOME	948,302	515,155	312,981
PREFERRED STOCK DIVIDENDS	(41,813)	(39,506)	(22,469)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(26,874)	(36,678)	
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 879,615	$ 438,971	$ 290,512
EARNINGS PER COMMON SHARE BASIC:			
Income before cumulative effect of accounting change	$ 2.73	$ 1.73	$ 1.36
Cumulative effect of accounting change			0.02
	$ 2.73	$ 1.73	$ 1.38

EARNINGS PER COMMON SHARE ASSUMING DILUTION:						
Income before cumulative effect of accounting change	$	2.51	$	1.53	$	1.20
Cumulative effect of accounting change						0.01
	$	2.51	$	1.53	$	1.21
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.195	$	0.170	$	0.135
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):						
Basic		322,034		253,212		211,203
Assuming dilution		366,683		305,718		258,567

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

	Years Ended December 31, 2005	2004	2003
	($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 948,302	$ 515,155	$ 312,981
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion, and amortization	935,965	605,593	382,004
Deferred income taxes	544,891	289,532	186,664
Loss on repurchases or exchanges of Chesapeake debt	70,419	24,557	20,759
Premiums paid for repurchasing of senior notes	(59,893)	(16,281)	(6,695)
Amortization of loan costs and bond discount	14,784	10,275	5,861
Unrealized (gains) losses on derivatives	(42,722)	(35,549)	(3,992)
Stock-based compensation	15,343	4,828	
Cumulative effect of accounting change			(3,853)
Loss on investment in Seven Seas			2,015
Other	(1,362)	4,412	1,490
(Increase) decrease in accounts receivable	(204,860)	(152,590)	(72,683)
(Increase) decrease in inventory and other assets	(66,979)	(9,481)	(10,971)
Increase (decrease) in accounts payable, accrued liabilities and other	92,215	97,635	86,861
Increase (decrease) in current and non-current revenues and royalties due others	160,785	94,188	38,466
Cash provided by operating activities	2,406,888	1,432,274	938,907
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(3,925,473)	(1,914,746)	(1,261,275)
Exploration and development of oil and gas properties	(2,371,854)	(1,276,341)	(727,231)
Additions to buildings and other fixed assets	(417,470)	(126,707)	(71,454)
Additions to investments	(135,013)	(36,962)	(30,750)
Additions to drilling rig equipment	(66,758)	(23,093)	(1,221)
Deposits for acquisitions	(35,000)	(16,250)	(13,250)
Divestitures of oil and gas properties	9,769	12,048	22,156
Sale of non-oil and gas assets and investments	20,422	860	5,799
Other	(1)	(13)	9
Cash used in investing activities	(6,921,378)	(3,381,204)	(2,077,217)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	5,682,000	2,160,000	738,000
Payments on long-term borrowings	(5,765,116)	(2,101,000)	(738,000)
Cash received from issuance of senior notes, net of offering costs	2,924,636	1,165,975	485,445
Proceeds from issuance of preferred stock, net of offering costs	1,341,529	304,936	390,365
Proceeds from issuance of common stock, net of offering costs	985,782	624,187	177,427
Cash paid to purchase or exchange senior notes	(565,868)	(248,434)	(106,379)
Cash paid for common stock dividends	(60,528)	(38,902)	(27,253)
Cash paid for preferred stock dividends	(31,480)	(40,907)	(20,916)
Cash paid for financing cost of credit facilities	(4,672)	(9,175)	(2,474)
Cash paid for treasury stock and preferred stock	(4,000)		(2,109)
Derivative settlements	(11,642)		
Net increase in outstanding payments in excess of cash balance	61,171	88,348	28,315

Other financing costs	(5,803)	(1,770)	(496)
Cash received from exercise of stock options and warrants	21,612	11,987	9,329
Cash provided by financing activities	4,567,621	1,915,245	931,254
Net increase (decrease) in cash and cash equivalents	53,131	(33,685)	(207,056)
Cash and cash equivalents, beginning of period	6,896	40,581	247,637
Cash and cash equivalents, end of period	$ 60,027	$ 6,896	$ 40,581

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

	Years Ended December 31,		
	2005	2004	2003
	($ in thousands)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 175,416	$ 134,000	$ 137,146
Income taxes, net of refunds received	$ 200	$ 239	$ 5,160

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

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, respectively, for 14,321,881 and 4,362,720 shares, respectively, of common stock in privately negotiated exchanges.

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

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

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

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

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

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

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

As of December 31, 2005, 2004 and 2003, dividends payable on our common and preferred stock were $37.9 million, $19.4 million and $15.7 million, respectively.

In 2005, 2004 and 2003 oil and gas properties were adjusted by $251.7 million, $463.9 million and ($4.9) million, respectively, for net tax liabilities related to acquisitions.

During 2005, 2004 and 2003, $27.3 million, $29.7 million, and $18.1 million, respectively, of additions to oil and gas properties were recorded as an increase to accrued exploration and development costs.

We recorded non-cash asset additions to net oil and gas properties of $76.8 million, $20.2 million and $45.7 million in 2005, 2004 and 2003, respectively, for asset retirement obligations.

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, 2005	2004	2003
	($ in thousands)		
PREFERRED STOCK:			
Balance, beginning of period	$ 490,906	$ 552,400	$ 149,900
Issuance of 6.00% cumulative convertible preferred stock			230,000
Issuance of 5.00% cumulative convertible preferred stock (Series 2003)			172,500
Issuance of 4.125% cumulative convertible preferred stock		313,250	
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)	460,000		
Issuance of 4.50% cumulative convertible preferred stock	345,000		
Issuance of 5.00% cumulative convertible preferred stock (Series 2005B)	575,000		
Exchange of common stock for 224,190 shares of 4.125% preferred stock	(224,190)		
Exchange of common stock for 699,054 shares of 5.00% preferred stock (Series 2003)	(69,905)		
Exchange of common stock for 2,998,000 shares of 6.75% preferred stock		(149,900)	
Exchange of common stock for 3,800, 4,496,890 and 0 shares of 6.00% preferred stock, respectively	(190)	(224,844)	
Balance, end of period	1,576,621	490,906	552,400
COMMON STOCK:			
Balance, beginning of period	3,169	2,218	1,949
Issuance of 32,200,000, 46,000,000 and 23,000,000 shares of common stock, respectively	322	460	230
Exchange of 18,703,069, 43,447,299 and 0 shares of common stock for preferred stock	187	435	
Exercise of stock options and warrants	40	29	39
Restricted stock grants	37	27	
Balance, end of period	3,755	3,169	2,218
PAID-IN CAPITAL:			
Balance, beginning of period	2,440,105	1,389,212	1,205,554
Issuance of common stock	1,024,282	649,520	186,070
Exchange of 18,703,069, 43,447,299 and 0 shares of common stock for preferred stock, respectively	294,098	374,310	
Equity-based compensation	82,144	41,485	2,292
Offering expenses	(77,293)	(34,297)	(21,139)
Exercise of stock options and warrants	21,573	11,958	9,290
Tax benefit from exercise of stock options and restricted stock	18,506	9,135	7,145
Preferred stock conversion/exchange expenses	(103)	(1,218)	
Balance, end of period	3,803,312	2,440,105	1,389,212
RETAINED EARNINGS (DEFICIT):			
Balance, beginning of period	262,987	(168,617)	(426,085)
Net income	948,302	515,155	312,981
Dividends on common stock	(64,830)	(45,229)	(29,128)
Dividends on preferred stock	(45,618)	(38,322)	(26,385)
Balance, end of period	1,100,841	262,987	(168,617)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	20,425	(20,312)	(3,461)
Gain (loss) on hedging activity	(266,312)	15,946	(16,851)
Unrealized gain on marketable securities	50,915	24,791	
Balance, end of period	(194,972)	20,425	(20,312)

UNEARNED COMPENSATION:			
Balance, beginning of period	(32,618)		
Restricted stock granted	(79,979)	(38,949)	
Amortization of unearned compensation	23,355	6,331	
Balance, end of period	(89,242)	(32,618)	
TREASURY STOCK COMMON:			
Balance, beginning of period	(22,091)	(22,091)	(19,982)
Purchase of 257,220, 0 and 279,042 shares of treasury stock, respectively	(4,000)		(2,109)
401(k) make-up plan distribution of 8,525 shares	99		
Balance, end of period	(25,992)	(22,091)	(22,091)
TOTAL STOCKHOLDERS EQUITY	$ 6,174,323	$ 3,162,883	$ 1,732,810

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,		
	2005	2004	2003
		($ in thousands)	
Net Income	$ 948,302	$ 515,155	$ 312,981
Other comprehensive income (loss), net of income tax:			
Change in fair value of derivative instruments, net of income taxes of ($317,772,000), ($44,463,000) and ($15,272,000), respectively	(552,837)	(79,046)	(24,917)
Reclassification of (gain) loss on settled contracts, net of income taxes of $136,841,000, $50,480,000 and $1,448,000, respectively	238,066	89,743	2,363
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $27,850,000, $2,953,000 and $3,495,000, respectively	48,452	5,249	5,703
Unrealized gain on marketable securities, net of income taxes of $29,266,000, $13,945,000 and $0, respectively	50,915	24,791	
Other adjustments, net of income taxes of $3,000	6		
Comprehensive income	$ 732,904	$ 555,892	$ 296,130

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 acquisition, exploration and development of properties for the production of crude oil and natural gas from underground reservoirs and the marketing of natural gas and oil for other working interest owners in properties we operate. Our properties are located in Oklahoma, Texas, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota, New Mexico, West Virginia, Kentucky, Ohio, New York, Maryland, Michigan, Pennsylvania, Tennessee and Virginia.

Principles of Consolidation

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

Accounting Estimates

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

Cash Equivalents

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

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 gas inventory is recorded at the lower of weighted average cost or market.

Oil and Gas Properties

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities (see Note 11). Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. As of December 31, 2005, approximately 78% of our proved reserves were evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers evaluate all properties on an annual basis. The average composite rates used for depreciation, depletion and amortization were $1.91 per equivalent mcfe in 2005, $1.61 per equivalent mcfe in 2004, and $1.38 per equivalent mcfe in 2003.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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 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, geographical 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 and Drilling Rigs

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

	December 31,		
	2005	2004	Useful Life
	($ in thousands)		(in years)
Land	$ 74,466	$ 24,153	
Buildings and improvements	156,110	105,516	15 39
Gathering, processing and compression equipment	406,408	112,888	7 20
Other fixtures and equipment	113,099	81,938	2 7
Drilling rigs	116,133	49,375	15
Total	$ 866,216	$ 373,870	

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investments

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

Included in investments at December 31, 2005 are equity securities totaling $297.4 million. At December 31, 2005, investments accounted for under the equity method totaled $57.8 million and investments accounted for under the cost method totaled $239.6 million. Included in the investments accounted for under the cost method are an investment in the common stock of Pioneer Drilling Company (AMEX:PDC) reported at a fair market value of $138.1 million (cost basis of $42.7 million) and an investment in the common stock of Gastar Exploration Ltd. (AMEX: GST) reported at a fair market value of $98.4 million (cost basis of $76.0 million). The fair market value of our investments in Pioneer Drilling Company and Gastar Exploration Ltd. at December 31, 2005 are based upon the closing price of their common stock ($17.93 per share and $3.63 per share, respectively).

Capitalized Interest

During 2005, 2004 and 2003, interest of approximately $79.0 million, $36.2 million and $13.0 million, respectively, was capitalized on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate on our outstanding borrowings.

Accounts Payable and Accrued Liabilities

Included in accounts payable at December 31, 2005 and 2004, respectively, are liabilities of approximately $177.8 million and $116.7 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 $88.3 million and $61.0 million of accrued drilling costs as of December 31, 2005 and 2004, respectively.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and costs associated with our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2005 and 2004 totaled $92.2 million and $54.4 million, respectively, and are being amortized over the life of the senior notes or revolving credit facility.

Asset Retirement Obligations

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Revenue Recognition

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

Gas Imbalances. We follow the sales method of accounting for our gas revenue whereby we recognize sales revenue on all gas sold to our purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of the remaining gas reserves on the underlying properties. The gas imbalance net position at December 31, 2005 and 2004 was a liability of $4.5 million and $4.4 million, respectively.

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

Hedging

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

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

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

in oil and gas sales. For derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings.

Stock Options

Chesapeake has elected to follow APB No. 25, *Accounting for Stock Issued to Employees*, and related interpretations in accounting for its employee and director stock options. Under APB No. 25, compensation expense is recognized for the difference between the option exercise price and market value on the measurement date. The original issuance of stock options has not resulted in the recognition of compensation expense because the exercise price of the stock options granted under the plans has equaled the market price of the underlying stock on the date of grant. Pursuant to FASB Interpretation No. 44 (FIN 44), which addresses the accounting consequence of various modifications to the terms of a previously granted fixed-price stock option, we recognized stock-based compensation expense in the consolidated statements of operations of $3.9 million, $0.6 million and $0.9 million in 2005, 2004 and 2003, respectively. Of the $3.9 million recognized in 2005, $1.2 million was capitalized to oil and gas properties.

Pro forma information regarding net income and earnings per share is required by Statement of Financial Accounting Standards No. 123, *Stock-based Compensation* and has been determined as if we had accounted for our employee and director stock options under the fair value method of the statement. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions for 2005, 2004 and 2003, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) ranging from 2.24% to 4.35%, dividend yields ranging from 0.52% to 1.53%, and volatility factors of the expected market price of our common stock ranging from 0.29 to 0.46. We used a weighted-average expected life of the options of five years for each of 2005, 2004 and 2003.

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

	Years Ended December 31,		
	2005	2004	2003
	($ in thousands, except per share amounts)		
Net Income:			
As reported	$ 948,302	$ 515,155	$ 312,981
Stock-based compensation expense included in net income, net of tax	9,743	3,090	586
Pro forma compensation expense, net of tax	(18,028)	(14,289)	(11,604)
Pro forma	$ 940,017	$ 503,956	$ 301,963
Basic earnings per common share:			
As reported	$ 2.73	$ 1.73	$ 1.38
Pro forma	$ 2.71	$ 1.69	$ 1.32
Diluted earnings per common share:			
As reported	$ 2.51	$ 1.53	$ 1.21
Pro forma	$ 2.48	$ 1.49	$ 1.17

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In December 2004, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment*, which revised the accounting for stock-based compensation under SFAS 123. This statement establishes standards for the accounting of transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123(R) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. That cost will be recognized over the period during which an employee is required to provide services in exchange for the award. The fair value of employee stock options will be estimated using option-pricing models. Excess tax benefits will be recognized as an addition to paid-in capital. Cash retained as a result of those excess tax benefits will be presented in the statement of cash flows as financing cash inflows. The write-off of deferred tax assets relating to unrealized tax benefits associated with recognized compensation cost will be recognized as income tax expense unless there are excess tax benefits from previous awards remaining in paid-in capital to which it can be offset. This statement is effective as of the beginning of the first annual reporting period that begins after June 15, 2005. Chesapeake will implement SFAS 123(R) in the first quarter of 2006 utilizing the modified prospective method, with the Black-Scholes option pricing model continuing to be used to value the stock options as of the grant date. Based on the stock options outstanding and unvested at December 31, 2005 and our current intention to limit future awards of stock options, we do not believe the requirement to expense stock options under SFAS No. 123 (R) will have a significant impact on future results of operations. Chesapeake began issuing shares of restricted common stock to employees in 2004 and to directors in 2005.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 2004 and 2003 to conform to the presentation used for the 2005 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 years ended December 31, 2005, 2004 and 2003, outstanding options to purchase 0.1 million, 0.1 million and 1.9 million shares of common stock at a weighted-average exercise price of $29.85, $23.82 and $11.15, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.

For the year ended December 31, 2005, diluted shares do not include the common stock equivalent of the 4.125% preferred stock (convertible into 8,610,708 shares) as the effect was antidilutive, and the preferred stock adjustment to net income does not include $28.9 million of dividends and loss on conversion/exchange related to these preferred shares.

For the year ended December 31, 2004, diluted shares do not include the common stock equivalent of the 6% preferred stock outstanding prior to conversion (convertible into 21,339,375 shares) as the effect was antidilutive and the preferred stock dividend adjustment to net income does not include $12.2 million of dividends related to these preferred shares.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the year ended December 31, 2003, outstanding warrants to purchase 0.4 million shares of common stock at a weighted-average exercise price of $14.55 were antidilutive because the exercise price of the warrants was greater than the average market price of the common stock.

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

A reconciliation for the years ended December 31, 2005, 2004 and 2003 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Year ended December 31, 2005:			
Basic EPS:			
Income available to common shareholders	$ 879,615	322,034	$ 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		5,349	
Common shares assumed issued for 4.50% convertible preferred stock		2,332	
Common shares assumed issued for 5.00% (Series 2003) convertible preferred stock		6,254	
Common shares assumed issued for 5.00% (Series 2005) convertible preferred stock		12,532	
Common shares assumed issued for 5.00% (Series 2005B) convertible preferred stock		2,177	
Common shares assumed issued for 6.00% convertible preferred stock		483	
Common stock equivalent of preferred stock outstanding prior to conversion, 5.00% (Series 2003) convertible preferred stock		3,024	
Common stock equivalent of preferred stock outstanding prior to conversion, 6.00% convertible preferred stock		12	
Preferred stock dividends	36,278		
Loss on redemption of preferred stock	3,519		
Employee stock options		10,861	
Restricted stock		1,614	
Warrants assumed in Gothic acquisition		11	
Diluted EPS Income available to common shareholders and assumed conversions	$ 919,412	366,683	$ 2.51

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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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, 2005 and 2004:

	December 31, 2005	December 31, 2004
	($ in thousands)	
7.5% Senior Notes due 2013	$ 363,823	$ 363,823
7.0% Senior Notes due 2014	300,000	300,000
7.5% Senior Notes due 2014	300,000	300,000
7.75% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	
6.875% Senior Notes due 2016	670,437	670,437
6.5% Senior Notes due 2017	600,000	
6.25% Senior Notes due 2018	600,000	
6.875% Senior Notes due 2020	500,000	
2.75% Contingent Convertible Senior Notes due 2035 (a)	690,000	
8.375% Senior Notes due 2008		18,990
8.125% Senior Notes due 2011		245,407
9.0% Senior Notes due 2012		300,000
Revolving bank credit facility	72,000	59,000
Discount on senior notes	(95,577)	(84,924)
Premium (discount) for interest rate derivatives (b)	(11,349)	1,968
Total notes payable and long-term debt	$ 5,489,742	$ 3,075,109

(a) The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes.

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

During the past three years, we have repurchased or exchanged Chesapeake debt and incurred losses in connection with these transactions. The following table shows the losses related to these transactions for 2005, 2004 and 2003, respectively ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Year Ended December 31, 2005:	**Retired**	**Premium**	**Other (a)**	**Total**
8.375% Senior Notes due 2008	$ 19.0	$ 1.2	$ 0.1	$ 1.3
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 564.4	$ 59.9	$ 10.5	$ 70.4
For the Year Ended December 31, 2004:				
8.375% Senior Notes due 2008	$ 190.8	$ 16.1	$ 1.5	$ 17.6

8.5% Senior Notes due 2012	4.3	0.2	0.7	0.9
8.125% Senior Notes due 2011	482.8		6.0	6.0
	$ 677.9	$ 16.3	$ 8.2	$ 24.5
For the Year Ended December 31, 2003:				
8.5% Senior Notes due 2012	$ 106.4	$ 6.7	$ 14.1(b)	$ 20.8

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

The senior note indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures (issued before July 2005) contain covenants limiting our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by all of our domestic wholly owned subsidiaries.

As of February 2006, we have a $2.0 billion syndicated revolving bank credit facility which matures in February 2011. As of December 31, 2005, we had $72 million of outstanding borrowings under our facility and utilized $53 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies from 0.125% to 0.30% according to our senior unsecured long-term debt ratings. Currently, the annual commitment fee rate is 0.25%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, purchase or redeem our capital stock, make investments or loans, and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. At December 31, 2005, our indebtedness to total capitalization ratio was 0.48 to 1 and our indebtedness to EBITDA ratio was 2.34 to 1. If we should fail to perform our obligations under these and other covenants, the revolving

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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

4. Contingencies and Commitments

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

Employment Agreements with Officers. Currently, Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and various other senior management personnel, which provide for annual base salaries, bonus compensation and various benefits. The agreements provide for the continuation of salary and benefits for varying terms in the event of termination of employment without cause. The agreement with the chief executive officer has a term of five years commencing July 1, 2005. The term of the agreement is automatically extended for one additional year on each January 31 unless the company provides 30 days notice of non-extension. The agreements with the chief operating officer, chief financial officer and other senior managers expire on September 30, 2006. The company s employment agreements with the executive officers provide for payments in the event of a change in control. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation and three-times the value of the prior year s benefits, plus a tax gross-up payment, any stock-based awards held by the chief executive officer will immediately become 100% vested, and any unexercised options will not terminate as a result of his termination of employment. The company will also provide him office space and secretarial and accounting support for a period of 12 months after a change of control. The chief operating officer, chief financial officer and other officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year. See further discussion regarding the resignation of our former chief operating officer in Note 16 of the notes to our consolidated financial statements.

Environmental Risk. Due to the nature of the oil and gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at December 31, 2005.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Leases. Chesapeake has entered into various operating leases for office space and equipment. Future minimum lease payments required as of December 31, 2005 related to these operating leases are as follows ($ in thousands):

2006	$ 4,124
2007	3,473
2008	2,837
2009	2,204
2010	419
After 2010	702
Total	$ 13,759

Rent expense, including short-term rentals, for the years ended December 31, 2005, 2004 and 2003 was $29.8 million, $17.9 million and $13.1 million, respectively.

Transportation Contracts. In connection with the November 14, 2005 acquisition of Columbia Natural Resources, LLC, Chesapeake assumed various firm pipeline transportation service agreements with expiration dates ranging from one to 94 years. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company will receive rights to flow natural gas production through pipelines located in highly competitive markets. The aggregate amount of such required demand payments as of December 31, 2005 are as follows (in thousands):

2006	$ 7,406
2007	3,331
2008	2,972
2009	2,525
2010	1,076
After 2010	95,467
Total	$ 112,777

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

Drilling Contracts. We have contracts with various drilling contractors to use 36 drilling rigs in 2006 with terms of one to three years. Minimum future commitments as of December 31, 2005 are as follows (in thousands):

2006	$ 153,321
2007	98,375
2008	62,697
2009	8,818
After 2009	

Total	$ 323,211

Chesapeake s wholly owned subsidiary, Nomac Drilling Corporation, as of December 31, 2005, had contracted to acquire 26 rigs to be constructed during 2006. The total cost of the rigs is estimated to be approximately $227 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Additionally through Nomac Drilling Corporation, as of December 31, 2005, we had agreed to acquire 13 drilling rigs and related assets from Martex Drilling Company, L.L.P., a privately-held drilling contractor with operations in East Texas and North Louisiana, for $150 million, which was completed in February 2006.

Other. On December 23, 2005, Chesapeake and a leading investment bank entered into an agreement to lend Mountain Drilling Company up to $25 million each. The agreement matures on December 31, 2009. There were no outstanding borrowings under this agreement at December 31, 2005.

In connection with the CNR acquisition, Chesapeake assumed obligations under forward gas sales agreements to deliver natural gas through February 2006. As of December 31, 2005, the remaining 4.25 bcf of gas scheduled to be delivered under this contract was recorded as a $60.9 million current accrued liability, based on the fair value of the delivery commitment at the date of acquisition.

As of December 31, 2005, Chesapeake had agreed to acquire oil and natural gas assets located in its Barnett Shale, South Texas, Permian Basin, Mid-Continent and East Texas regions from private companies for an aggregate purchase price of approximately $700 million in cash.

As of December 31, 2005, we had agreed to acquire a privately held Oklahoma-based trucking company for $48 million. This acquisition closed in January 2006.

As of December 31, 2005, we had agreed to acquire office buildings in Oklahoma City for $35.5 million. These acquisitions closed in January 2006.

5. Income Taxes

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

	Years Ended December 31,		
	2005	2004	2003
	($ in thousands)		
Current	$	$	$ 5,000
Deferred	545,091	289,771	186,824
Total	$ 545,091	$ 289,771	$ 191,824(a)

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

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

	Years Ended December 31,		
	2005	2004	2003
	($ in thousands)		
Computed expected federal income tax provision	$ 522,688	$ 281,724	$ 176,682
State income taxes and other	22,608	8,230	10,968
Change in valuation allowance			4,364
Tax percentage depletion	(205)	(183)	(190)

	$ 545,091	$ 289,771	$ 191,824

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31, 2005	2004
	($ in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$ (2,227,960)	$ (1,121,776)
Other property and equipment	(26,679)	(18,128)
Derivative instruments		(10,798)
Investments	(42,211)	(5,944)
Deferred tax liabilities	$ (2,296,850)	$ (1,156,646)
Deferred tax assets:		
Net operating loss carryforwards	$ 246,857	$ 199,897
Asset retirement obligation	59,525	26,907
Derivative instruments	358,660	
Accrued liabilities	30,648	1,643
Percentage depletion carryforwards	4,603	3,801
Alternative minimum tax credits	5,298	5,344
Other	20,873	3,249
Deferred tax assets	$ 726,464	$ 240,841
Total deferred tax asset (liability)	$ (1,570,386)(a)	$ (915,805)
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 234,592	$ 18,068
Non-current deferred income tax liability	(1,804,978)	(933,873)
	$ (1,570,386)	$ (915,805)

(a) In addition to the income tax expense of $545.1 million, activity during 2005 includes a net liability of $251.7 million related to acquisitions, a benefit of $153.1 million related to derivative instruments, a liability of $29.6 million related to investments, a benefit of $18.5 million related to stock-based compensation, and a benefit of $0.2 million related to other miscellaneous items. These items were not recorded as part of the provision for income taxes.

SFAS 109 requires that we record a valuation allowance when it is more likely than not that some portion or all of deferred tax assets will not be realized. During 2004, we determined that it was more likely than not that $6.8 million of the deferred tax assets related to Louisiana net operating losses, upon which we had previously recorded a valuation allowance, would be realized due to the acquisitions occurring in 2004. The recognition of the deferred tax asset was included as a component of the acquisition of the properties and was not reflected as a reduction of the 2004 provision for income tax.

As of December 31, 2005, we classified $234.6 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences. As of December 31, 2004, we classified $18.1 million of deferred tax assets as current that were attributable to the current portion of derivative liabilities and other current temporary differences.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At December 31, 2005, Chesapeake had federal income tax net operating loss (NOL) carryforwards of approximately $564.5 million. Additionally, we had $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 these carryforwards depends on the ability of Chesapeake to generate taxable income. In addition, for AMT purposes, only 90% of AMT income in any given year may be offset by AMT NOLs. A summary of our NOLs follows:

	NOL	AMT NOL
	($ in thousands)	
Expiration Date:		
December 31, 2012	$ 171,588	$
December 31, 2018	42,187	
December 31, 2019	145,855	57,414
December 31, 2020	5,155	1,393
December 31, 2021	15,370	5,313
December 31, 2022	50,410	25,299
December 31, 2023	65,273	37,648
December 31, 2024	60,349	40,062
December 31, 2025	8,264	2,506
Total	$ 564,451	$ 169,635

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, 2005 and any related limitations:

	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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Related Party Transactions

As of December 31, 2005, we had accrued accounts receivable from our two co-founders, CEO Aubrey K. McClendon and former COO Tom L. Ward, of $6.4 million and $6.4 million, respectively, representing joint interest billings from December 2005 which were invoiced and paid in January 2006. Since Chesapeake was founded in 1989, Messrs. McClendon and Ward have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. Joint interest billings to them are settled in cash immediately upon delivery of a monthly joint interest billing.

Under the Founder Well Participation Program, approved by our shareholders in June 2005, Messrs. McClendon and Ward may elect to participate in all or none of the wells drilled by or on behalf of Chesapeake, but they are not allowed to participate only in selected wells. A participation election is required to be received by the Compensation Committee of Chesapeake s Board of Directors 30 days prior to the start of each calendar year. Their participation is permitted only under the terms outlined in the Founder Well Participation Program, which, among other things, limits their individual participation to a maximum working interest of 2.5% in a well and prohibits participation in situations where Chesapeake s working interest would be reduced below 12.5% as a result of their participation. In addition, the company is reimbursed for the cost of its leasehold acquired by Messrs. McClendon and Ward as a result of their well participation. As a result of the resignation of Mr. Ward on February 10, 2006, his participation in the Founder Well Participation Program will expire on August 10, 2006, which is also the expiration date of non-competition covenants applicable to Mr. Ward.

As disclosed in Note 8, in 2005, Chesapeake had revenues of $851.4 million from oil and gas sales to Eagle Energy Partners I, L.P., an affiliated entity.

During 2005, 2004 and 2003, we paid legal fees of $1.2 million, $1.1 million and $2.1 million, respectively, for legal services provided by a law firm of which a former director is a member.

7. Employee Benefit Plans

We maintain two qualified 401(k) profit sharing plans, the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, which is open to employees of Chesapeake and all our subsidiaries except Nomac Drilling Corporation, and the Nomac Drilling 401(k) Plan, which is open to employees of Nomac Drilling Corporation. Eligible employees may elect to defer voluntary contributions to the plans, subject to plan limits and those set by the Internal Revenue Service. Chesapeake matches contributions to the Chesapeake Savings and Incentive Stock Bonus Plan dollar for dollar with Chesapeake common stock purchased in the open market for up to 15% of an employee s annual compensation. The company contributed $10.0 million, $6.9 million and $4.0 million to this plan during 2005, 2004 and 2003, respectively. The company matched contributions to the Nomac Drilling 401(k) Plan dollar for dollar with Chesapeake common stock purchased in the open market for up to 8% of the participating employee s annual compensation during 2005. Prior to 2005, the matching contribution to the Nomac plan was 6%. The company contributed $0.4 million, $0.2 million and $0.1 million to this plan in 2005, 2004 and 2003, respectively.

In November 2005, Chesapeake acquired Columbia Natural Resources, LLC., which sponsors 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. Employees that were offered employment with Chesapeake effective January 1, 2006 are eligible to participate in Chesapeake s 401(k) plan. This group of employees includes employees in the Charleston, WV headquarters office as well as exempt, administrative field employees. Existing assets of these participants are scheduled for transfer to the Chesapeake plan on March 1, 2006. All non-administrative field employees, including union employees, are excluded from participation in the

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Chesapeake plan and will continue participation in the existing CNR plan. This plan will remain active and will be adopted by the new employer entity, Chesapeake Appalachia, L.L.C.

In January 2003, we established a 401(k) make-up plan and a deferred compensation plan, both of which are nonqualified deferred compensation plans. To be eligible to participate in the 401(k) make-up plan during 2004 and 2003, an employee had to receive annual compensation (base salary and bonus combined) of at least $90,000, have a minimum of five years of service as a company employee and have made the maximum contribution allowable under the 401(k) plan. The company matched employee contributions to the 401(k) make-up plan in Chesapeake common stock dollar for dollar for up to 15% of the employee s annual compensation. In December 2004, Chesapeake amended the 401(k) make-up plan and the deferred compensation plan in response to the American Jobs Creation Act of 2004, which set out new guidelines for such plans. The compensation eligibility threshold (base salary and bonus combined) for the 401(k) make-up plan was adjusted to $95,000 in 2005 to correspond with the IRS annual limitations. Effective January 1, 2006, the compensation eligibility threshold (base salary and bonus combined) for the 401(k) make-up plan was increased to $100,000. We contributed $1.6 million, $1.4 million and $1.2 million to the 401(k) make-up plan during 2005, 2004 and 2003, respectively.

Non-employee directors and employees with at least one year of service receiving an annual base salary of at least $100,000 during the 12 months prior to the enrollment date were eligible to participate in the deferred compensation plan in 2003 and 2004. In 2005, the annual base salary compensation limit required for eligibility in the deferred compensation plan was reduced to $95,000. Non-employee directors are able to defer up to 100% of director fees. The maximum compensation that can be deferred under all company deferred compensation plans, including the Chesapeake 401(k) plan, has been increased to a total of 75% of base salary and 100% of performance bonus. Chesapeake made no matching or other contributions to the deferred compensation plan, although the plan permits the company to make discretionary contributions.

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

Chesapeake maintains no post-employment benefit plans except those sponsored by CNR. CNR employees who elected to accept employment with Chesapeake effective January 1, 2006 are no longer eligible to participate in the CNR post-employment benefit plans. As of December 31, 2005, a total of 193 employees remained eligible for these plans. The CNR 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, 2005, the company had accrued $2.6 million in accumulated post-employment benefit liability.

8. Major Customers and Segment Information

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

Year Ended December 31,	Customer	Amount ($ in thousands)	Percent of Total Revenues
2005	Eagle Energy Partners I, L.P.	$ 851,420	18%
2004	Eagle Energy Partners I, L.P.	$ 467,387	17%
2003	Reliant Energy Services	$ 189,140	11%
2003	Duke Energy Field Services	$ 163,329	10%

In September 2003, Chesapeake invested $5.8 million in Eagle Energy Partners I, L.P. and received a 25% limited partnership interest. Through additional investments totaling $3.4 million, Chesapeake has increased its

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

limited partner ownership interest to approximately 33% as of December 31, 2005. Chesapeake accounts for its investment in Eagle Energy Partners I, L.P. under the equity method of accounting in accordance with APB 18. In October 2005, Chesapeake purchased a fixed volume of gas in storage from Eagle Energy Partners I, L.P. for approximately $29 million. Along with the gas storage purchased, Chesapeake assumed hedging contracts which Eagle had previously negotiated covering the gas in storage. These hedges have scheduled maturities beginning in December 2005 and ending in March 2006. Eagle Energy has agreed to periodically purchase the gas in storage from Chesapeake at market prices plus a premium of $0.1125 per mcfe beginning in December 2005 and ending in March 2006. As of December 31, 2005, the remaining gas storage had a market value of $29.6 million and the assumed hedges had a market value of ($6.7) million.

In accordance with SFAS 131, *Disclosures about Segments of an Enterprise and Related Information*, we have identified two reportable operating segments. These segments are managed separately because of the nature of their products and services. Chesapeake s two reportable segments are the exploration and production segment and the marketing segment. Based upon the growth of the company s drilling rig operations in 2005, drilling operations have been presented in Other for all years presented. These operations previously had been considered a part of the exploration and production segment.

The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, transporting and selling natural gas and crude oil primarily from Chesapeake operated wells.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Management evaluates the performance of our segments based upon income before income taxes and cumulative effect of accounting change. Revenues from the marketing segment s sale of oil and gas related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $2,395.9 million, $1,349.1 million and $875.3 million for 2005, 2004 and 2003, respectively. Revenues and associated expenses from the drilling of oil and gas wells on Chesapeake-operated properties generally are eliminated and included as part of the carrying value of our oil and gas properties. The following tables present selected financial information for Chesapeake according to our operating segments:

For the Year Ended December 31, 2005:	Exploration and Production	Marketing	Other Operations ($ in thousands)	Intercompany Eliminations	Consolidated Total
Revenues	$ 3,272,585	$ 3,788,653	$ 60,755	$ (2,456,703)	$ 4,665,290
Intersegment revenues		(2,395,948)	(60,755)	2,456,703	
Total Revenues	3,272,585	1,392,705			4,665,290
Depreciation, depletion and amortization	939,904	5,097	5,897	(5,897)	945,001
Interest and other income	9,684	523	299	(54)	10,452
Interest expense	219,800				219,800
Other expense	70,419				70,419
INCOME BEFORE INCOME TAXES	$ 1,466,652	$ 26,496	$ 10,089	$ (9,844)	$ 1,493,393
TOTAL ASSETS	$ 15,123,840	$ 688,747	$ 305,875	$	$ 16,118,462
CAPITAL EXPENDITURES	$ 7,696,400	$ 132,817	$ 69,945	$	$ 7,899,162
For the Year Ended December 31, 2004:					
Revenues	$ 1,936,176	$ 2,122,235	$ 22,864	$ (1,372,007)	$ 2,709,268
Intersegment revenues		(1,349,143)	(22,864)	1,372,007	
Total Revenues	1,936,176	773,092			2,709,268
Depreciation, depletion and amortization	602,894	8,428	3,775	(3,775)	611,322
Interest and other income	3,944	532	240	(240)	4,476
Interest expense	167,328				167,328
Other expense	24,557				24,557
INCOME BEFORE INCOME TAXES	$ 801,583	$ 3,343	$ (1,995)	$ 1,995	$ 804,926
TOTAL ASSETS	$ 7,810,772	$ 318,246	$ 115,491	$	$ 8,244,509
CAPITAL EXPENDITURES	$ 3,845,851	$ 42,462	$ 23,957	$	$ 3,912,270
For the Year Ended December 31, 2003:					
Revenues	$ 1,296,822	$ 1,295,872	$ 15,652	$ (890,914)	$ 1,717,432
Intersegment revenues		(875,262)	(15,652)	890,914	
Total Revenues	1,296,822	420,610			1,717,432
Depreciation, depletion and amortization	383,065	3,193	3,485	(3,485)	386,258
Interest and other income	1,673	1,154	29	(29)	2,827
Interest expense	154,345	11			154,356
Other expense	22,774				22,774
INCOME BEFORE INCOME TAXES	$ 496,133	$ 4,819	$ (1,996)	$ 1,996	$ 500,952
TOTAL ASSETS	$ 4,340,673	$ 195,733	$ 35,885	$	$ 4,572,291

CAPITAL EXPENDITURES	$ 2,084,896	$ 27,265	$ 1,206	$	$ 2,113,367

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Stockholders Equity, Restricted Stock and Stock Options

The following is a summary of the changes in our common shares outstanding for 2005, 2004 and 2003:

	2005	2004	2003
		(in millions)	
Shares outstanding, beginning of year	317	222	195
Stock option and warrant exercises	4	3	4
Restricted stock issuances	4	3	
Preferred stock conversions	19	43	
Common stock issuances	32	46	23
Shares outstanding, end of year	376	317	222

The following is a summary of the changes in our preferred shares outstanding for 2005, 2004 and 2003:

	6.75%	6.00%	5% (2003)	4.125%	5% (2005)	4.50%	5% (2005B)
Shares outstanding, 1/1/05		103,110	1,725,000	313,250			
Preferred stock issuances					4,600,000	3,450,000	5,750,000
Conversion of preferred		(3,800)					
Exchanges of preferred for common stock			(699,054)	(224,190)			
Shares outstanding, 12/31/05		99,310	1,025,946	89,060	4,600,000	3,450,000	5,750,000
Shares outstanding, 1/1/04	2,998,000	4,600,000	1,725,000				
Preferred stock issuances				313,250			
Conversion by holder	(960,000)						
Mandatory conversion	(2,038,000)						
Exchange of preferred for common stock		(600,000)					
Registered exchange offer		(3,896,890)					
Shares outstanding, 12/31/04		103,110	1,725,000	313,250			
Shares outstanding, 1/1/03	2,998,000						
Preferred stock issuances		4,600,000	1,725,000				
Shares outstanding, 12/31/03	2,998,000	4,600,000	1,725,000				

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

In 2005, holders of our 6.00% cumulative convertible preferred stock converted 3,800 shares into 18,468 shares of our common stock.

In 2005, holders of our 5.00% (Series 2003) cumulative convertible preferred stock converted 699,054 shares into 4,362,720 shares of our common stock.

In 2005, holders of our 4.125% cumulative convertible preferred stock converted 224,190 shares into 14,321,881 shares of our common stock.

In April 2005, we issued 4,600,000 shares of 5.00% (Series 2005) cumulative convertible preferred stock, par value $0.01 per share and liquidation preference $100 per share, in a private offering, all of which were

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

outstanding as of December 31, 2005. The net proceeds from the offering were $447.2 million. Each share of preferred stock is convertible, at the holder s option at any time, initially into approximately 3.8811 shares of our common stock based on an initial conversion price of $25.766 per share, subject to specified adjustments. At December 31, 2005, 17,853,060 shares of our common stock were reserved for issuance upon conversion. The preferred stock is subject to mandatory conversion, at our option, on or after April 15, 2010 (1) at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $33.50, for a specified time period and (2) at the lower of the conversion price and the then current market price of common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $5.00 per share are payable quarterly on the fifteenth day of each January, April, July and October.

In September 2005, we issued 3,450,000 shares of 4.50% cumulative convertible preferred stock, par value of $0.01 per share and liquidation preference $100 per share, in a public offering, all of which were outstanding as of December 31, 2005. The net proceeds from the offering were $335.2 million. Each share of preferred stock is convertible, at the holder s option at any time, initially into approximately 2.2639 shares of our common stock based on an initial conversion price of $44.172 per share, subject to specified adjustments. At December 31, 2005, 7,810,455 shares of our common stock were reserved for issuance upon conversion. The preferred stock is subject to mandatory conversion, at our option, on or after September 15, 2010 (1) at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $57.42, for a specified time period and (2) at the lower of the conversion price and the then current market price of common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $4.50 per share are payable quarterly on the fifteenth day of each March, June, September and December.

In September 2005, we issued 9,200,000 shares of Chesapeake common stock at $32.72 per share in a public offering for net proceeds of $289.4 million.

In November 2005, we issued 5,750,000 shares of 5.00% (Series 2005B) cumulative convertible preferred stock, par value of $0.01 per share and liquidation preference $100 per share, in a private offering, all of which were outstanding as of December 31, 2005. The net proceeds from the offering were $559.1 million. Each share of preferred stock is convertible, at the holder s option at any time, initially into approximately 2.5595 shares of our common stock based on an initial conversion price of $39.07 per share, subject to specified adjustments. At December 31, 2005, 14,717,125 shares of our common stock were reserved for issuance upon conversion. The preferred stock is subject to mandatory conversion, at our option, on or after November 15, 2010 (1) at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $50.79, for a specified time period and (2) at the lower of the conversion price and the then current market price of common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $5.00 per share are payable quarterly on the fifteenth day of each February, May, August and November.

In December 2005, we issued 23,000,000 shares of Chesapeake common stock at $31.46 per share in a public offering for net proceeds of $696.4 million.

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

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In March and April 2004, we issued 313,250 shares of 4.125% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $1,000 per share, in a private offering, 89,060 shares of which were outstanding as of December 31, 2005. The net proceeds from the offering were $304.9 million. Each share of preferred stock is convertible initially into 60.0555 shares of common stock (which is calculated using an initial conversion price of $16.65 per share of common stock), subject to adjustment upon the occurrence of certain events. A holder s right to convert will arise only when (i) the closing sale price of our common stock reaches or exceeds 130% of the conversion price for a specified period of time; (ii) the trading price of the preferred stock falls below 98% of the product of the closing sale price of our common stock and the conversion price for a specified period of time; or (iii) upon the occurrence of certain corporate transactions. At December 31, 2005, 5,348,542 shares of our common stock were reserved for issuance upon conversion. The preferred stock is subject to mandatory conversion, at our option, on or after March 15, 2009 (1) at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $21.65, for a specified time period and (2) at the lower of the conversion price and the then current market price of common stock if there are less than 25,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $41.25 per share are payable quarterly on the fifteenth day of each March, June, September and December.

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

In November 2003, we issued 1,725,000 shares of 5.00% (Series 2003) cumulative convertible preferred stock, par value $.01 per share and liquidation preference $100 per share, in a public offering, 1,025,946 of which were outstanding as of December 31, 2005. The net proceeds from the offering were $167.6 million. Each preferred share is convertible at any time at the option of the holder into 6.0962 shares of common stock, subject to adjustment. At December 31, 2005, 6,254,372 shares of our common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $16.40 per common share plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion, at our option, (1) on or after November 18, 2006 at the same rate, if the market price of the common stock equals or exceeds 130% of the conversion price, or $21.32, for a specified time period and (2) on or after November 18, 2008, at the lower of the conversion price and the then current market price of common stock if there are less than 250,000 shares of preferred stock outstanding at the time. Annual cumulative cash dividends of $5.00 per share are payable quarterly on the fifteenth day of each February, May, August and November.

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

In March 2003, we issued 4,600,000 shares of 6.00% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $50 per share, in a private offering, 99,310 shares of which were outstanding as of December 31, 2005. The net proceeds from the offering were $222.8 million. Each preferred share is convertible at any time at the option of the holder into 4.8605 shares of common stock, subject to adjustment. At December 31, 2005, 482,696 shares of common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $10.287 per common share plus cash in lieu of fractional shares. The preferred stock is subject to mandatory conversion at our option, (1) on or after March 20, 2006 at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price, or $13.37, at the time and (2) on or after March 20, 2008 at the lower of the conversion price and the then current market price of the common stock if there are less than 250,000 shares of preferred stock outstanding at the time.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Annual cumulative cash dividends of $3.00 per share are payable quarterly on the fifteenth day of March, June, September and December.

Restricted Stock

During 2005 and 2004, Chesapeake issued 3.9 million shares and 2.7 million shares, respectively, of restricted common stock to directors and employees. The total value of restricted shares granted is recorded as unearned compensation in stockholders equity based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is four years from the date of grant. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to oil and gas properties. Amounts not capitalized to oil and gas properties are recognized in general and administrative expense. Chesapeake recognized amortization of compensation cost related to restricted stock totaling $23.3 million and $6.3 million during 2005 and 2004. Of these amounts, $12.6 million and $4.2 million were reflected in general and administrative expense with the remaining $10.7 million and $2.1 million capitalized to oil and gas properties. As of December 31, 2005 and 2004, the unamortized balance of unearned compensation recorded as a reduction of stockholders equity was $89.2 million and $32.6 million.

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 2005, we recognized a tax benefit of $2.0 million, which was recorded as an adjustment to additional paid-in capital and deferred income taxes with respect to such benefits.

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 which may be issued and sold may not exceed 3,000,000 shares. The maximum period for exercise of an option or stock appreciation right may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option or stock appreciation right on the date of grant. Awards granted under the plan become vested at dates or upon the satisfaction of certain performance or other criteria determined by a committee of the board of directors. No awards may be granted under this plan after September 30, 2014. This plan has been approved by our shareholders. Stock options to purchase 150,000 and 50,000 shares of our common stock were issued to our directors from this plan in 2005 and 2004, respectively. In addition, 62,500 shares of restricted stock were issued to our directors from this plan in 2005. As of December 31, 2005, there were 2.7 million shares remaining available for issuance under the plan.

Under Chesapeake s 2003 Stock Incentive Plan, restricted stock and incentive and nonqualified stock options to purchase our common stock may be awarded to employees and consultants of Chesapeake. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 10,000,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price may not be less than the fair market value of the shares underlying the option on the date of grant. Restricted stock and options granted become vested at dates determined by a committee of the board of directors. No awards may be granted under this plan after April 14, 2013. This plan has been approved by our shareholders. There were 3.9 million restricted shares, net of forfeitures, issued during 2005 from this plan. As of December 31, 2005, there were 3.7 million shares remaining available for issuance under the plan.

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Under Chesapeake s 2003 Stock Award Plan for Non-Employee Directors, 10,000 shares of Chesapeake s common stock will be awarded to each newly appointed non-employee director on his or her first day of service. Subject to any adjustments as provided by the plan, the aggregate number of shares which may be issued may not exceed 50,000 shares. This plan was not required to be approved by our shareholders. In 2005, 10,000 shares of common stock were awarded to a new director from this plan. As of December 31, 2005, there are 30,000 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. No shares remained available for option grants under the plans as of December 31, 2005. 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. 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. Beginning in 2004, stock-based compensation awards to employees have been made in the form of restricted stock from the 2003 Stock Incentive Plan.

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

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

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

	Years Ended December 31,					
	2005		2004		2003	
	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price
Outstanding beginning of period	24,228,464	$ 6.00	27,233,285	$ 5.78	24,576,775	$ 4.40
Granted	177,500	18.67	347,250	14.23	7,168,623	8.98
Exercised	(4,032,180)	5.78	(3,219,877)	4.94	(4,262,915)	3.04
Canceled/forfeited	(117,771)	8.51	(132,194)	8.21	(249,198)	8.51
Outstanding end of period	20,256,013	$ 6.14	24,228,464	$ 6.00	27,233,285	$ 5.78
Exercisable end of period	15,960,440	$ 5.57	15,441,511	$ 5.06	12,131,098	$ 4.26
Shares authorized for future grants	6,452,444		8,392,285		11,018,225	
Fair value of options granted during period	$ 6.21		$ 4.66		$ 3.36	

The following table summarizes information about stock options outstanding at December 31, 2005:

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	$ 1.13	2,381,599	2.89	$ 1.08	2,381,599	$ 1.08
1.38	4.00	2,183,302	4.17	3.26	2,183,302	3.26
4.06	4.06	2,058	2.46	4.06	2,058	4.06
5.20	5.20	2,714,939	6.56	5.20	1,836,849	5.20
5.35	5.96	1,812,027	4.90	5.57	1,787,912	5.56
6.11	6.11	4,777,753	5.75	6.11	4,776,816	6.11
6.13	7.74	252,771	5.78	6.91	222,673	6.87
7.80	7.80	2,739,115	7.02	7.80	1,124,867	7.80
7.86	10.01	258,106	6.63	8.48	184,345	8.55
10.08	30.63	3,134,343	7.74	11.46	1,460,019	12.78
$ 0.94	$30.63	20,256,013	5.72	$ 6.14	15,960,440	$ 5.57

The exercise of certain stock options results in state and federal income tax benefits to us related to the difference between the market price of the common stock at the date of disposition and the option price. During 2005, 2004 and 2003, we recognized tax benefits of $16.5 million, $9.1 million and $7.1 million, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Shareholder Rights Plan

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

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

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

10. Financial Instruments and Hedging Activities

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2005, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

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

Basis protection swaps are arrangements that guarantee a price differential for oil or gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

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

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

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

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

Chesapeake enters into derivatives from time to time for the purpose of converting a fixed price gas sales contract to a floating price. We refer to these contracts as floating-price swaps. For a floating-price swap, Chesapeake receives a floating market price from the counterparty and pays a fixed price.

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

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or gas from a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual prices we receive for much of our gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future gas price differentials. As of December 31, 2005, the fair value of our basis protection swaps was $307.3 million. Currently, our basis protection swaps cover approximately 24% of our anticipated gas production in 2006, 24% in 2007, 20% in 2008 and 14% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the consolidated statements of operations. Realized gains (losses) included in oil and gas sales were ($401.7) million, ($154.9) million and ($17.4) million in 2005, 2004 and 2003, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales were $41.1 million, $40.9 million and $10.5 million, in 2005, 2004 and 2003, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as unrealized gains (losses). We recorded a gain (loss) on ineffectiveness of ($76.3) million, ($8.2) million and ($9.2) million in 2005, 2004 and 2003, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The estimated fair values of our oil and gas derivative instruments (including derivatives acquired from CNR) as of December 31, 2005 and 2004 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	December 31, 2005	December 31, 2004
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ (1,047,094)	$ 57,073
Gas basis protection swaps	307,308	122,287
Fixed-price gas cap-swaps	(161,056)	(48,761)
Fixed-price gas counter-swaps	37,785	4,654
Gas call options (a)	(21,461)	(5,793)
Fixed-price gas collars	(9,374)	(5,573)
Fixed-price gas locked swaps	(34,229)	(77,299)
Floating-price gas swaps	2,607	
Fixed-price oil swaps	(16,936)	
Fixed-price oil cap-swaps	(3,364)	(8,238)
Estimated fair value	$ (945,814)	$ 38,350

(a) After adjusting for the remaining $23.0 million and $3.2 million premium paid to Chesapeake by the counterparty, the cumulative unrealized gain (loss) related to these call options as of December 31, 2005 and 2004 was $1.6 million and ($2.6) million, respectively.

Based upon the market prices at December 31, 2005, we expect to transfer approximately $153.8 million (net of income taxes) of the loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of December 31, 2005 are expected to mature by December 31, 2009.

We have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for these facilities is May 2010. Outstanding transactions under each facility are collateralized by certain of our oil and gas properties that do not secure any of our other obligations. One of the hedging facilities is subject to an annual fee of 0.30% of the maximum total capacity, and each of them has a 1.0% exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of December 31, 2005, the fair market value of the natural gas and oil hedging transactions was a liability of $92.9 million under one of the facilities and a liability of $10.9 million under the other facility. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. As of March 10, 2006, the fair market value of the same transactions was an asset of approximately $100 million and $400 million, respectively. The agreements also contain various restrictive provisions which govern the aggregate gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. 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 is 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 will result in adjustments to our oil and gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change then upon the sale of the underlying

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and 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 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 have hedged the production volumes listed below market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, A*mendment 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 will be reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following details the CNR derivatives we have assumed:

	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, 2005 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
1Q 2006	7,872,500	4.91			Yes	(50,693)
2Q 2006	10,510,500	4.86			Yes	(56,501)
3Q 2006	10,626,000	4.86			Yes	(57,355)
4Q 2006	10,626,000	4.86			Yes	(62,483)
1Q 2007	10,350,000	4.82			Yes	(68,401)
2Q 2007	10,465,000	4.82			Yes	(46,158)
3Q 2007	10,580,000	4.82			Yes	(46,442)
4Q 2007	10,580,000	4.82			Yes	(51,557)
1Q 2008	9,555,000	4.68			Yes	(53,954)
2Q 2008	9,555,000	4.68			Yes	(33,892)
3Q 2008	9,660,000	4.68			Yes	(33,999)
4Q 2008	9,660,000	4.66			Yes	(38,487)
1Q 2009	4,500,000	5.18			Yes	(18,772)
2Q 2009	4,550,000	5.18			Yes	(10,450)
3Q 2009	4,600,000	5.18			Yes	(10,508)
4Q 2009	4,600,000	5.18			Yes	(12,616)
Total						(652,268)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(3,380)
2Q 2009	910,000		4.50	6.00	Yes	(1,754)
3Q 2009	920,000		4.50	6.00	Yes	(1,773)
4Q 2009	920,000		4.50	6.00	Yes	(2,197)
Total						(9,104)
Total Natural Gas						$ (661,372)

Interest Rate Derivatives

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2005, the following interest rate swaps were used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value Gain (Loss) ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,734)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	$ (5,133)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	$ (5,327)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	$ (5,004)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	$ (1,344)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	$ (3,240)
October 2005 January 2016	$ 200,000,000	6.625%	6 month LIBOR plus 129 basis points	$ 282

In January 2006, we closed the interest rate swap on our 6.625% Senior Notes for $1.0 million. Subsequent to December 31, 2005, we entered into the following interest rate swaps (which qualify as fair value hedges) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points
March 2006 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 125.5 basis points

In 2005, we closed various interest rate swaps for gains totaling $7.1 million respectively. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

In March 2004, Chesapeake entered into an interest rate swap which required Chesapeake to pay a fixed rate of 8.68% while the counterparty paid Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. On March 15, 2005, we elected to terminate the interest rate swap and paid $31.8 million to the counterparty.

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 items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at December 31, 2005 and 2004 were $5.429 billion and $3.014 billion, respectively, compared to approximate fair values of $5.582 billion and $3.281 billion, respectively. The carrying amounts for our convertible preferred stock as of December 31, 2005 and 2004 were $1.577 billion and $490.9 million, respectively, compared to approximate fair values of $1.686 billion and $533.7 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Concentration of Credit Risk

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

11. Supplemental Disclosures About Oil And Gas Producing Activities

Net Capitalized Costs

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

	December 31, 2005	December 31, 2004
	($ in thousands)	
Oil and gas properties:		
Proved	$ 15,880,919	$ 9,451,413
Unproved	1,739,095	761,785
Total	17,620,014	10,213,198
Less accumulated depreciation, depletion and amortization	(3,945,703)	(3,057,742)
Net capitalized costs	$ 13,674,311	$ 7,155,456

Unproved properties not subject to amortization at December 31, 2005 and 2004 consisted mainly of leasehold acquired through corporate and significant oil and gas property acquisitions and through direct purchases of leasehold. We capitalized approximately $79.0 million, $36.2 million and $13.0 million of interest during 2005, 2004 and 2003, 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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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Costs Incurred in Oil and Gas Acquisition, Exploration and Development

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

	Years Ended December 31,		
	2005	2004	2003
		($ in thousands)	
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.

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

Chesapeake s results of operations from oil and gas producing activities are presented below for 2005, 2004 and 2003. The following table includes revenues and expenses associated directly with our oil and 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 gas operations.

	Years Ended December 31,		
	2005	2004	2003
		($ in thousands)	
Oil and gas sales (a)	$ 3,272,585	$ 1,936,176	$ 1,296,822
Production expenses	(316,956)	(204,821)	(137,583)

Production taxes	(207,898)	(103,931)	(77,893)
Depletion and depreciation	(894,035)	(582,137)	(369,465)
Imputed income tax provision (b)	(676,599)	(376,303)	(270,515)
Results of operations from oil and gas producing activities	$ 1,177,097	$ 668,984	$ 441,366

(a) Includes $41.1 million, $40.9 million and $10.5 million of unrealized gains (losses) on oil and gas derivatives for the years ended December 31, 2005, 2004 and 2003, 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Oil and 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 2005, 2004 and 2003 is presented below.

	Years ended December 31,		
	2005	**2004**	**2003**
Netherland, Sewell & Associates, Inc.	25%	23%	24%
Data and Consulting Services, Division of Schlumberger Technology Corporation	16		
Lee Keeling and Associates, Inc.	15	22	16
Ryder Scott Company L.P.	12	13	34
LaRoche Petroleum Consultants, Ltd.	8	10	
H.J. Gruy and Associates, Inc.	2	6	
Miller and Lents, Ltd.		1	
Internal petroleum engineers	22	25	26
	100%	100%	100%

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

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Presented below is a summary of changes in estimated reserves of Chesapeake for 2005, 2004 and 2003:

	Oil (mbbl)	Gas (mmcf)	Total (mmcfe)
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
December 31, 2004			
Proved reserves, beginning of period	51,422	2,860,040	3,168,575
Extensions, discoveries and other additions	7,601	771,125	816,728
Revisions of previous estimates	6,109	108,863	145,518
Production	(6,764)	(322,009)	(362,593)
Sale of reserves-in-place	(102)	(3,329)	(3,940)
Purchase of reserves-in-place	29,694	959,299	1,137,463
Proved reserves, end of period	87,960	4,373,989	4,901,751
Proved developed reserves:			
Beginning of period	38,442	2,121,734	2,352,389
End of period	62,713	2,842,141	3,218,418
December 31, 2003			
Proved reserves, beginning of period	37,587	1,979,601	2,205,125
Extensions, discoveries and other additions	3,574	359,681	381,123
Revisions of previous estimates	1,329	48,388	56,365
Production	(4,665)	(240,366)	(268,356)
Sale of reserves-in-place	(183)	(9,626)	(10,723)
Purchase of reserves-in-place	13,780	722,362	805,041
Proved reserves, end of period	51,422	2,860,040	3,168,575
Proved developed reserves:			
Beginning of period	28,111	1,458,284	1,626,952

End of period	38,442	2,121,734	2,352,389

During 2005, Chesapeake acquired approximately 2.041 tcfe of proved reserves through purchases of oil and gas properties for consideration of $3.806 billion (primarily in 18 separate transactions of greater than $10 million each). We also sold 0.5 bcfe of proved reserves for consideration of approximately $9.8 million. During 2005, we recorded upward revisions of 41 bcfe to the December 31, 2004 estimates of our reserves. Approximately 24 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2005.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $56.41 per bbl and $8.76 per mcf at December 31, 2005.

During 2004, Chesapeake acquired approximately 1.137 tcfe of proved reserves through purchases of oil and gas properties for consideration of $2.006 billion (primarily in fifteen separate transactions of greater than $10 million each). We also sold 4 bcfe of proved reserves for consideration of approximately $12.0 million. During 2004, we recorded upward revisions of 146 bcfe to the December 31, 2003 estimates of our reserves. Approximately 5 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2004. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $39.91 per bbl and $5.65 per mcf at December 31, 2004.

During 2003, Chesapeake acquired approximately 805 bcfe of proved reserves through purchases of oil and gas properties for consideration of $1.105 billion (primarily in nine separate transactions of greater than $10 million each). We also sold 11 bcfe of proved reserves for consideration of approximately $22.2 million. During 2003, we recorded upward revisions of 56 bcfe to the December 31, 2002 estimates of our reserves. Approximately 11.1 bcfe of the upward revisions was caused by higher oil and gas prices at December 31, 2003. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The weighted average oil and gas wellhead prices used in computing our reserves were $30.22 per bbl and $5.68 per mcf at December 31, 2003.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31, 2005	2004 ($ in thousands)	2003
Future cash inflows	$ 66,286,940(a)	$ 28,245,336(b)	$ 17,807,624(c)
Future production costs	(14,794,530)	(6,542,219)	(3,816,607)
Future development costs	(4,676,287)	(2,115,511)	(912,594)
Future income tax provisions	(14,856,446)	(5,663,575)	(3,827,408)
Future net cash flows	31,959,677	13,924,031	9,251,015
Less effect of a 10% discount factor	(15,991,766)	(6,278,492)	(3,924,262)
Standardized measure of discounted future net cash flows	$ 15,967,911	$ 7,645,539	$ 5,326,753

(a) Calculated using weighted average prices of $56.41 per barrel of oil and $8.76 per mcf of gas.
(b) Calculated using weighted average prices of $39.91 per barrel of oil and $5.65 per mcf of gas.
(c) Calculated using weighted average prices of $30.22 per barrel of oil and $5.68 per mcf of gas.

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

	Years Ended December 31, 2005	2004 ($ in thousands)	2003
Standardized measure, beginning of period (a)	$ 7,645,539	$ 5,326,753	$ 2,833,918
Sales of oil and gas produced, net of production costs (b)	(3,108,277)	(1,741,438)	(1,088,184)
Net changes in prices and production costs	3,249,132	(730,020)	(2,364)
Extensions and discoveries, net of production and development costs	3,144,966	1,784,166	1,041,108
Changes in future development costs	(151,133)	33,284	74,719
Development costs incurred during the period that reduced future development costs	490,902	226,415	130,195
Revisions of previous quantity estimates	122,924	317,518	99,927
Purchase of reserves-in-place (c)	6,252,030	2,580,973	2,012,686
Sales of reserves-in-place (c)	(939)	(5,604)	(827)
Accretion of discount	1,050,439	733,314	371,765
Net change in income taxes	(4,106,833)	(852,462)	(1,122,661)
Changes in production rates and other	1,379,161	(27,360)	976,471
Standardized measure, end of period (a)	$ 15,967,911	$ 7,645,539	$ 5,326,753

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

(c) In 2003, purchases and sales of reserves are shown net of the 9.9 bcfe which was acquired and immediately sold for $19 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Asset Retirement Obligations

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

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

	Years Ended December 31,	
	2005	2004
	($ in thousands)	
Asset retirement obligations, beginning of period	$ 73,718	$ 48,812
Additions	51,168	21,862
Revisions (a)	26,731	
Settlements and disposals	(1,087)	(1,613)
Accretion expense	6,063	4,657
Asset retirement obligations, end of period	$ 156,593	$ 73,718

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

13. Acquisitions and Divestitures

The following table describes acquisitions that we completed in 2005 ($ in millions):

Acquisition	Location	Amount
Columbia Natural Resources, LLC	Appalachian Basin	$ 2,200(a)
BRG Petroleum Corporation	Mid-Continent and Ark-La-Tex	325(b)
Laredo Energy II, L.L.C.	South Texas	228
Hallwood Energy, III L.P.	Barnett Shale	250(c)
Houston-based oil and gas company	Texas Gulf Coast/South Texas	202
Pecos Production Company	Permian	198
Laredo II Partners	Texas Gulf Coast/South Texas	139
Corpus Christi-based oil and gas company	Ark-La-Tex	95
Dallas-based oil and gas company	Ark-La-Tex	85
Midland-based oil and gas company	Permian	38
Other	Various	372(d)
		$ 4,132

(a) Includes $175 million related to gathering systems which was allocated to other property and equipment.
(b) We paid $16.3 million of the purchase amount in 2004.
(c) Includes $15 million related to gathering systems which was allocated to other property and equipment.
(d)

In 2005, we paid the remaining $57 million of the purchase price related to an acquisition transaction with Hallwood Energy Corporation in the fourth quarter of 2004.

During 2005, we recorded approximately $252 million of deferred tax liability to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

The strategic benefits of the CNR acquisition include the significant addition of land and gas resource inventories to complement Chesapeake s already extensive resource inventories. In addition, the underexplored and unconsolidated Appalachian Basin has very similar characteristics to the Mid-Continent region in which Chesapeake already has a significant stronghold.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Quarterly Financial Data (unaudited)

Summarized unaudited quarterly financial data for 2005 and 2004 are as follows ($ in thousands except per share data):

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

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

(a) Total revenue less operating costs.
(b) Includes a pre-tax loss on repurchases and exchanges of debt of $0.9 million.
(c) Includes a pre-tax loss on repurchases and exchanges of debt of $68.4 million.
(d) Includes a pre-tax loss on repurchases and exchanges of debt of $0.7 million.
(e) Includes a pre-tax loss on repurchases and exchanges of debt of $0.4 million.
(f) Includes a pre-tax loss on repurchases and exchanges of debt of $6.9 million.
(g) Includes a pre-tax loss on repurchases and exchanges of debt of $17.6 million.

15. Recently Issued Accounting Standards

The Financial Accounting Standards Board recently issued the following standards which we reviewed to determine the potential impact on our financial statements upon adoption.

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment*, which revised SFAS 123, *Accounting for Stock-Based Compensation*. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123(R) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. This statement is effective as of the beginning of the first annual reporting period that begins after June 15, 2005. Since the issuance of SFAS 123(R), three FASB Staff Positions (FSPs) have been issued regarding SFAS 123(R): FSP FAS 123(R)-1 *Classification and Measurement of Freestanding Financial Instruments Originally Issued in Exchange for Employee Services under FASB Statement No. 123(R)*, FSP FAS 123(R)-2 *Practical Accommodation to the Application of Grant Date as Defined in FASB Statement No. 123(R),* and FSP FAS 123(R)-3 *Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards.* These FSPs will be applicable upon the initial adoption of FAS 123(R). The effect of SFAS123(R) is more fully described in Note 1.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In March 2005, the FASB issued FASB Interpretation No. (FIN) 47, *Accounting for Conditional Asset Retirement Obligations*. FIN 47 specifies the accounting treatment for conditional asset retirement obligations under the provisions of SFAS 143. FIN 47 is effective no later than the end of the fiscal year ending after December 15, 2005. We adopted this statement effective December 31, 2005. Implementation of FIN 47 did not have a material effect on our financial statements.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3.* SFAS 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors after the effective date, but we do not currently expect SFAS 154 to have a material impact on our financial statements.

In June 2005, the EITF reached a consensus on Issue No. 04-10, *Determining Whether to Aggregate Operating Segments That Do Not Meet the Quantitative Thresholds*. EITF Issue 04-10 confirmed that operating segments that do not meet the quantitative thresholds can be aggregated only if aggregation is consistent with the objective and basic principles of SFAS 131, *Disclosure about Segments of an Enterprise and Related Information*. The consensus in this issue should be applied for fiscal years ending after September 30, 2005, and the corresponding information for earlier periods, including interim periods, should be restated unless it is impractical to do so. The adoption of EITF Issue 04-10 is not expected to have a material impact on our disclosures.

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

16. Subsequent Events

On January 17, 2006, we announced that we had entered into agreements with private companies to acquire oil and natural gas assets in the Barnett Shale, south Texas, Permian basin, Mid-Continent and East Texas regions for an aggregate purchase price of approximately $700 million in cash. We have recently closed transactions for approximately $640 million in cash and expect to close the remaining acquisition by March 31, 2006. The pending acquisition is subject to customary closing conditions and purchase price adjustments.

On January 5, 2006, we acquired a privately-held Oklahoma-based trucking company for $48 million.

On February 3, 2006, we amended and restated our revolving bank credit facility, increasing the commitments to $2 billion and extending the maturity date to February 2011.

In February 2006, through our wholly-owned subsidiary Nomac Drilling Corporation, we acquired 13 drilling rigs and related assets from Martex Drilling Company, L.L.P., a privately-held drilling contractor with operations in East Texas and North Louisiana, for $150 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On February 3, 2006, we issued an additional $500 million of our 6.5% Senior Notes due 2017, in a private placement. Net proceeds from the offering were approximately $486.6 and were used to repay outstanding borrowings under our revolving bank credit facility, incurred primarily to finance our recent acquisitions.

On February 10, 2006, we sold our investment in Pioneer Drilling Company (AMEX: PDC) common stock for proceeds of $159 million and a pre-tax gain of $116 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.

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Schedule II

CHESAPEAKE ENERGY CORPORATION

VALUATION AND QUALIFYING ACCOUNTS

($ in thousands)

Description	Balance at Beginning of Period	Additions: Charged To Expense	Additions: Charged To Other Accounts	Deductions	Balance at End of Period
December 31, 2005:					
Allowance for doubtful accounts	$ 4,648	$ 114	$ 142	$	$ 4,904
Valuation allowance for deferred tax assets	$	$	$	$	$
December 31, 2004:					
Allowance for doubtful accounts	$ 2,669	$ 975	$ 1,004	$	$ 4,648
Valuation allowance for deferred tax assets	$ 6,805	$	$	$ 6,805(a)	$
December 31, 2003:					
Allowance for doubtful accounts	$ 1,433	$ 156	$ 1,202	$ 122	$ 2,669
Valuation allowance for deferred tax assets	$ 2,441	$ 4,364	$	$	$ 6,805

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

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ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***
Not applicable.

ITEM 9A. ***Controls and Procedures***
We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of December 31, 2005, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective as of December 31, 2005, to ensure that information required to be disclosed by Chesapeake is accumulated and communicated to Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

No changes in the company s internal control over financial reporting occurred during the quarter ended December 31, 2005 that have materially affected, or are reasonably likely to materially affect, the company s internal control over financial reporting.

Management s Report on Internal Control Over Financial Reporting

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

ITEM 9B. ***Other Information***
Unregistered Sales of Equity Securities.

In 2005 and the first quarter of 2006, Chesapeake entered into unsolicited transactions with holders of our 4.125% Cumulative Convertible Preferred Stock and 5.0% (Series 2003) Cumulative Convertible Preferred Stock to issue shares of our common stock in exchange for the 4.125% and 5.0% (Series 2003) preferred stock. The issuances of the shares of common stock in these transactions were exempt from registration under the Securities Act of 1933 pursuant to Rule 3(a)(9). The following transactions have not been previously reported under Item 3.02 *Unregistered Sales of Equity Securities* of Form 8-K because, in the aggregate, the number of shares of common stock issued is less than 1% of our total common shares outstanding:

Transaction Date	Preferred Series	Preferred Shares Received	Liquidation Value of Pref. Shares	Common Shares Issued
11/9/2005	4.125%	26,185	$26,185,000	1,662,608
11/9/2005	4.125%	3,100	3,100,000	196,833
11/9/2005	4.125%	2,000	2,000,000	126,990
12/14/2005	4.125%	1,750	1,750,000	109,813
12/20/2005	4.125%	1,000	1,000,000	62,842
12/20/2005	4.125%	3,000	3,000,000	188,407
1/18/2006	4.125%	1,700	1,700,000	106,731
1/19/2006	5.0% (2003)	125,000	12,500,000	777,655
1/20/2006	4.125%	1,050	1,050,000	65,863
1/20/2006	5.0% (2003)	18,000	1,800,000	111,980

1/23/2006	5.0% (2003)	40,273	4,027,300	250,588
		223,058	$58,112,300	3,660,310

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PART III

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

The information called for by this Item 10 is incorporated herein by referenced to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 28, 2006.

ITEM 11. ***Executive Compensation***

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 28, 2006.

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

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 28, 2006.

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

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 28, 2006.

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

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 28, 2006.

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PART IV

ITEM 15. ***Exhibits, Financial Statement Schedules***

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

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

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

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

Exhibit Number	Description
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2005.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2005.
3.1.3*	Certificate of Designation of 6% Cumulative Convertible Preferred Stock, as amended.
3.1.4*	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended.
3.1.5*	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.
3.1.6	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2005.
3.1.7	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K dated September 13, 2005.
3.1.8	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K dated November 7, 2005.
3.2	Chesapeake s Amended and Restated Bylaws. Incorporated herein by reference to Exhibit 3.2 of Chesapeake s annual report on Form 10-K for the year ended December 31, 2003.
4.1	Indenture dated as of May 27, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s registration statement on Form S-4 (No. 333-116555). First Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Second Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.11.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004. Fourth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.

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Exhibit Number	Description
4.1.1*	Fifth Supplemental Indenture dated as of November 14, 2005 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.1.2*	Sixth Supplemental Indenture dated as of February 24, 2006 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2	Indenture dated as of August 2, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Trust Company, N.A., as Trustee, with respect to 7.0% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s registration statement on Form S-4 (No. 333-118378). First Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Second Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.12.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004. Fourth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
4.2.1*	Fifth Supplemental Indenture dated as of November 14, 2005 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.2.2*	Sixth Supplemental Indenture dated as of February 24, 2006 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3	Indenture dated as of December 20, 2002 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to our 7.75% Senior Notes due 2015. Incorporated herein by reference to Exhibit 4.5 to Chesapeake s registration statement on Form S-4 (No. 333-102445) First Supplemental Indenture dated as of February 14, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s report on Form 10-K/A for the year ended December 31, 2002. Second Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2003. Third Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2003. Fourth Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003. Fifth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Sixth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.6.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Seventh Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004. Eighth Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.

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Exhibit Number	Description
4.3.1*	Ninth Supplemental Indenture dated November 14, 2005 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.75% Senior Notes due 2015.
4.3.2*	Tenth Supplemental Indenture dated February 24, 2006 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.75% Senior Notes due 2015.
4.4	Agreement to furnish copies of unfiled long-term debt instruments. Incorporated herein by reference to Chesapeake s transition report on Form 10-K for the six months ended December 31, 1997.
4.5	Sixth Amended and Restated Credit Agreement, dated as of February 3, 2006, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, Bank of America, N.A., Calyon New York Branch and SunTrust Bank, as Co-Documentation Agents, and the several lenders from time to time parties thereto. Incorporated herein by reference to Exhibit 4.8 to Chesapeake s current report on Form 8-K dated February 8, 2006.
4.6	Indenture dated as of March 5, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013. First Supplemental Indenture dated as of May 1, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2003. Second Supplemental Indenture dated as of August 15, 2003. Incorporated herein by reference to Exhibit 4.7.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2003. Third Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003. Fourth Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Fifth Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.9.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Sixth Supplemental Indenture dated January 31, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004. Seventh Supplemental Indenture dated July 15, 2005. Incorporated herein by reference to Exhibit 4.9.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
4.6.1*	Eighth Supplemental Indenture dated November 14, 2005 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.
4.6.2*	Ninth Supplemental Indenture dated February 24, 2006 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 7.5% Senior Notes due 2013.
4.7	Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016. Incorporated herein by reference to Exhibit 4.2 to Chesapeake s registration statement on Form S-4/A (No. 333-110668). First Supplemental Indenture dated as of March 5, 2004. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003. Second Supplemental Indenture dated as of August 30, 2004. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Third Supplemental Indenture dated as of September 27, 2004. Incorporated herein by reference to Exhibit 4.10.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004. Fourth Supplemental Indenture dated as of January 31, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004. Fifth Supplemental Indenture dated July 15, 2005. Incorporated herein by reference to Exhibit 4.10.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.

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Exhibit Number	Description
4.7.1*	Sixth Supplemental Indenture dated November 14, 2005 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.
4.7.2*	Seventh Supplemental Indenture dated February 24, 2006 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2016.
4.8	Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s current report on Form 8-K dated December 14, 2004. First Supplemental Indenture dated January 31, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004. Second Supplemental Indenture dated May 13, 2005. Incorporated herein by reference to Exhibit 4.11.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005. Third Supplemental Indenture dated July 15, 2005. Incorporated by reference herein to Exhibit 4.11.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
4.8.1*	Fourth Supplemental Indenture dated November 14, 2005 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.
4.8.2*	Fifth Supplemental Indenture dated February 24, 2006 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.375% senior notes due 2015.
4.9	Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016. Incorporated herein by reference to Exhibit 4.12 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2005. First Supplemental Indenture dated as of July 15, 2005. Incorporated herein by reference to Exhibit 4.12.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
4.9.1*	Second Supplemental Indenture dated as of November 14, 2005 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016.
4.9.2*	Third Supplemental Indenture dated as of February 24, 2006 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.625% senior notes due 2016.
4.10	Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
4.10.1*	First Supplemental Indenture dated as of November 14, 2005 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018.
4.10.2*	Second Supplemental Indenture dated as of February 24, 2006 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.25% senior notes due 2018.
4.11	Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s current report on Form 8-K dated August 16, 2005.

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Exhibit Number	Description
4.11.1*	First Supplemental Indenture dated as of November 14, 2005 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.
4.11.2*	Second Supplemental Indenture dated as of February 1, 2006 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.
4.11.3*	Third Supplemental Indenture dated as of February 24, 2006 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.50% senior notes due 2017.
4.12	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 6.875% senior notes due 2020. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake s current report on Form 8-K dated November 8, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.3 to Chesapeake s registration statement on Form S-4 (No. 333-132263). Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.4 to Chesapeake s registration statement on Form S-4 (No. 333-132263).
4.13	Indenture dated as of November 8, 2005 among Chesapeake, as issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors and The Bank of New York Trust Company, N.A., as Trustee, with respect to 2.75% contingent convertible senior notes due 2035. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake s current report on Form 8-K dated November 8, 2005. First Supplemental Indenture dated as of November 14, 2005. Incorporated herein by reference to Exhibit 4.5 to Chesapeake s registration statement on Form S-3 (No. 333-132261). Second Supplemental Indenture dated as of February 24, 2006. Incorporated herein by reference to Exhibit 4.6 to Chesapeake s registration statement on Form S-3 (No. 333-132261).
4.14	Registration Rights Agreement dated as of November 8, 2005 among Chesapeake and the Initial Purchasers named therein, with respect to 6.875% Senior Notes due 2020. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake s current report on Form 8-K dated November 15, 2005.
4.15	Registration Rights Agreement dated as of February 3, 2006 among Chesapeake and the Initial Purchasers named therein, with respect to 6.5% Senior Notes due 2017. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake s current report on Form 8-K dated February 3, 2006.
10.1.1	Chesapeake s 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit A to Chesapeake s definitive proxy statement for its 2003 annual meeting of shareholders filed April 17, 2003.
10.1.1.1	Form of Restricted Stock Award Agreement for Chesapeake s 2003 Stock Incentive Plan. Incorporated herein by reference to Exhibit 10.1.14.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.2	Chesapeake s 1992 Nonstatutory Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.3	Chesapeake s 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Chesapeake s quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.4	Chesapeake s 1996 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake s definitive proxy statement for its 1996 annual meeting of shareholders.

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Exhibit Number	Description
10.1.4.1	Form of Incentive Stock Option Agreement for Chesapeake s 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.4.2	Form of Nonqualified Stock Option Agreement for Chesapeake s 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.5	Chesapeake s 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.1.5.1	Form of Nonqualified Stock Option Agreement for Chesapeake s 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.6	Chesapeake s 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.6.1	Form of Nonqualified Stock Option Agreement for Chesapeake s 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.7	Chesapeake s 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Chesapeake s quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.8	Chesapeake s 2001 Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake s definitive proxy statement for its 2001 annual meeting of shareholders filed April 30, 2001.
10.1.8.1	Form of Incentive Stock Option Agreement for Chesapeake s 2001 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.8.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.8.2	Form of Nonqualified Stock Option Agreement for Chesapeake s 2001 Stock Option Plan and 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.8.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.9	Chesapeake s 2001 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.9 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2001.
10.1.10	Chesapeake s 2001 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.10 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2001.
10.1.11	Chesapeake s 2002 Stock Option Plan. Incorporated herein by reference to Exhibit A to Chesapeake s definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.
10.1.11.1	Form of Incentive Stock Option Agreement for Chesapeake s 2002 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.11.2	Form of Nonqualified Stock Option Agreement for Chesapeake s 2002 Stock Option Plan and 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.12	Chesapeake s 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit B to Chesapeake s definitive proxy statement for its 2002 annual meeting of shareholders filed April 29, 2002.

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Exhibit Number	Description
10.1.12.1	Form of Stock Option Agreement for Chesapeake s 2002 Non-Employee Director Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.12.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.13	Chesapeake s 2002 Nonqualified Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.11 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2002.
10.1.14	Chesapeake s 2003 Stock Award Plan for Non-Employee Directors. Incorporated herein by reference to Exhibit 10.1.14 to Chesapeake s annual report of Form 10-K/A for the year ended December 31, 2002.
10.1.15	Chesapeake Energy Corporation 401(k) Make-Up Plan. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake s annual report on Form 10-K/A for the year ended December 31, 2002.
10.1.15.1	Chesapeake Energy Corporation 401(k) Make-Up Plan 2005. Incorporated herein by reference to Exhibit 10.1.15.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004.
10.1.16	Chesapeake Energy Corporation Deferred Compensation Plan. Incorporated herein by reference to Exhibit 10.1.16 to Chesapeake s annual report on Form 10-K/A for the year ended December 31, 2002.
10.1.16.1	Chesapeake Energy Corporation Deferred Compensation Plan 2005. Incorporated herein by reference to Exhibit 10.1.16.1 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2004.
10.1.17	Form of Stock Option Grant Notice. Incorporated herein by reference to Exhibit 10.1.15 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2004.
10.1.18	Chesapeake s Long Term Incentive Plan. Incorporated herein by reference to Exhibit A to Chesapeake s definitive proxy statement for its 2005 annual meeting of shareholders filed April 29, 2005.
10.1.18.1	Form of Non-Employee Director Stock Option Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.1 to Chesapeake s current report on Form 8-K dated June 16, 2005.
10.1.18.2	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.2 to Chesapeake s current report on Form 8-K dated June 16, 2005.
10.1.18.3	Form of Non-Employee Director Restricted Stock Award Agreement for the Long Term Incentive Plan. Incorporated herein by reference to Exhibit 10.1.18.3 to Chesapeake s current report on Form 8-K dated June 16, 2005.
10.1.19	Founder Well Participation Program. Incorporated herein by reference to Exhibit B to Chesapeake s definitive proxy statement for its 2005 annual meeting of shareholders filed April 29, 2005.
10.2.1	Fourth Amended and Restated Employment Agreement dated as of July 1, 2005, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Chesapeake s current report on Form 8-K dated June 16, 2005.
10.2.2	Fourth Amended and Restated Employment Agreement dated as of July 1, 2005, between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake s current report on Form 8-K dated June 16, 2005.

Exhibit Number	Description
10.2.3	Amended and Restated Employment Agreement dated as of July 1, 2003 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2003.
10.2.4	Employment Agreement dated as of July 1, 2003 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Chesapeake s current report on Form 8-K dated February 15, 2006.
10.2.5	Resignation Agreement dated as of February 10, 2006 between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake s current report on Form 8-K dated February 15, 2006.
10.2.8	Employment Agreement dated as of July 1, 2003 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2003.
10.2.9	Employment Agreement dated as of July 1, 2003 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.9 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 2003.
10.3	Form of Indemnity Agreement for officers and directors of Chesapeake and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Chesapeake s registration statement on Form S-1 (No. 33-55600).
10.4	Non-Employee Director Compensation. Incorporated herein by reference to Exhibit 10.4 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2005.
10.5 *	Named Executive Officer Compensation.
10.6	Rights Agreement dated July 15, 1998 between Chesapeake and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Chesapeake s registration statement on Form 8-A filed July 16, 1998. Amendment No. 1 dated September 11, 1998. Incorporated herein by reference to Exhibit 10.3 to Chesapeake s quarterly report on Form 10-Q for the quarter ended September 30, 1998.
10.6.1*	Amendment No. 2 dated March 3, 2006 to Rights Agreement dated July 15, 1998 between Chesapeake and UMB Bank, N.A., as Rights Agent.
12*	Ratios of Earnings to Fixed Charges and Preferred Dividends.
21*	Subsidiaries of Chesapeake.
23.1*	Consent of Pricewaterhouse Coopers, LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Data & Consulting Services, Division of Schlumberger Technology Corporation
23.4*	Consent of Lee Keeling and Associates, Inc.
23.5*	Consent of Ryder Scott Company L.P.
23.6*	Consent of LaRoche Petroleum Consultants, Ltd.
23.7*	Consent of H.J. Gruy and Associates, Inc.
23.8*	Consent of Miller and Lents, Ltd.
31.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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Exhibit Number	Description
31.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION

By /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon

Chairman of the Board and

Chief Executive Officer

Date: March 13, 2006

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

Signature	Capacity	Date
/s/ AUBREY K. MCCLENDON **Aubrey K. McClendon**	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 13, 2006
/s/ MARCUS C. ROWLAND **Marcus C. Rowland**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 13, 2006
/s/ MICHAEL A. JOHNSON **Michael A. Johnson**	Senior Vice President Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 13, 2006
/s/ RICHARD K. DAVIDSON **Richard K. Davidson**	Director	March 13, 2006
/s/ FRANK KEATING **Frank Keating**	Director	March 13, 2006
/s/ BREENE M. KERR **Breene M. Kerr**	Director	March 13, 2006
/s/ CHARLES T. MAXWELL **Charles T. Maxwell**	Director	March 13, 2006
/s/ DON NICKLES **Don Nickles**	Director	March 13, 2006

/s/ FREDERICK B. WHITTEMORE	Director	March 13, 2006
Frederick B. Whittemore		

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Annex B

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2006

¨ Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to

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

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 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

As of November 3, 2006, there were 436,865,417 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2006

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PART I. FINANCIAL INFORMATION

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2006	December 31, 2005
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 716	$ 60,027
Accounts receivable	735,005	791,194
Deferred income taxes		234,592
Short-term derivative instruments	1,097,578	10,503
Inventory and other	78,996	87,081
Total Current Assets	1,912,295	1,183,397
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	20,191,783	15,880,919
Unevaluated properties	3,440,181	1,739,095
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(4,913,749)	(3,945,703)
Total oil and natural gas properties, at cost based on full-cost accounting	18,718,215	13,674,311
Other property and equipment:		
Natural gas gathering systems	457,321	333,365
Drilling rigs	301,611	116,133
Buildings and land	381,751	233,467
Natural gas compressors	108,847	73,043
Other	205,781	110,208
Less: accumulated depreciation and amortization of other property and equipment	(172,563)	(128,640)
Total Property and Equipment	20,000,963	14,411,887
OTHER ASSETS:		
Investments	686,343	297,443
Long-term derivative instruments	604,796	78,860
Other assets	190,524	146,875
Total Other Assets	1,481,663	523,178
TOTAL ASSETS	$ 23,394,921	$ 16,118,462

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	September 30, 2006	December 31, 2005
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 754,996	$ 516,792
Short-term derivative instruments	81,438	577,681
Other accrued liabilities	398,611	364,501
Deferred income taxes	369,410	
Revenues and royalties due others	305,422	394,693
Accrued interest	94,395	110,421
Total Current Liabilities	2,004,272	1,964,088
LONG-TERM LIABILITIES:		
Long-term debt, net	7,861,108	5,489,742
Deferred income tax liability	2,903,688	1,804,978
Asset retirement obligation	179,149	156,593
Long-term derivative instruments	181,941	479,996
Revenues and royalties due others	22,962	22,585
Other liabilities	48,981	26,157
Total Long-Term Liabilities	11,197,829	7,980,051
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 0 and 99,310 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $0 and $4,965,500		4,966
5.00% cumulative convertible preferred stock (series 2003), 38,625 and 1,025,946 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $3,862,500 and $102,594,600	3,863	102,595
4.125% cumulative convertible preferred stock, 3,065 and 89,060 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $3,065,000 and $89,060,000	3,065	89,060
5.00% cumulative convertible preferred stock (series 2005), 4,600,000 shares issued and outstanding as of September 30, 2006 and December 31, 2005, entitled in liquidation to $460,000,000	460,000	460,000
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of September 30, 2006 and December 31, 2005, entitled in liquidation to $345,000,000	345,000	345,000
5.00% cumulative convertible preferred stock (series 2005B), 5,750,000 shares issued and outstanding as of September 30, 2006 and December 31, 2005, entitled in liquidation to $575,000,000	575,000	575,000
6.25% mandatory convertible preferred stock, 2,300,000 and 0 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $575,000,000 and $0	575,000	
Common Stock, $.01 par value, 750,000,000 and 500,000,000 shares authorized, 437,859,397 and 375,510,521 shares issued at September 30, 2006 and December 31, 2005, respectively	4,379	3,755
Paid-in capital	4,899,634	3,803,312
Retained earnings	2,495,215	1,100,841

Accumulated other comprehensive income (loss), net of tax of ($518,564,000) and $112,071,000, respectively	862,241	(194,972)
Unearned compensation		(89,242)
Less: treasury stock, at cost; 1,306,528 and 5,320,816 common shares as of September 30, 2006 and December 31, 2005, respectively	(30,577)	(25,992)
Total Stockholders Equity	10,192,820	6,174,323
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 23,394,921	$ 16,118,462

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	($ in thousands, except per share data)			
REVENUES:				
Oil and natural gas sales	$ 1,493,226	$ 720,928	$ 4,190,430	$ 2,032,271
Oil and natural gas marketing sales	398,114	361,915	1,170,091	882,040
Service operations revenue	38,071		97,473	
Total Revenues	1,929,411	1,082,843	5,457,994	2,914,311
OPERATING COSTS:				
Production expenses	124,045	80,765	364,134	222,660
Production taxes	40,562	53,102	129,858	136,313
General and administrative expenses	37,382	15,785	99,728	39,640
Oil and natural gas marketing expenses	384,473	353,510	1,131,521	860,789
Service operations expense	18,821		48,925	
Oil and natural gas depreciation, depletion and amortization	343,723	231,145	976,839	621,484
Depreciation and amortization of other assets	27,016	12,902	74,051	34,791
Employee retirement expense			54,753	
Total Operating Costs	976,022	747,209	2,879,809	1,915,677
INCOME FROM OPERATIONS	953,389	335,634	2,578,185	998,634
OTHER INCOME (EXPENSE):				
Interest and other income	5,132	2,428	19,742	7,790
Interest expense	(74,112)	(58,593)	(220,226)	(155,623)
Gain on sale of investment			117,396	
Loss on repurchases or exchanges of Chesapeake senior notes		(747)		(70,047)
Total Other Income (Expense)	(68,980)	(56,912)	(83,088)	(217,880)
INCOME BEFORE INCOME TAXES	884,409	278,722	2,495,097	780,754
INCOME TAX EXPENSE:				
Current				
Deferred	336,074	101,734	963,136	284,977
Total Income Tax Expense	336,074	101,734	963,136	284,977
NET INCOME	548,335	176,988	1,531,961	495,777
PREFERRED STOCK DIVIDENDS	(25,753)	(10,204)	(62,793)	(25,526)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK		(17,725)	(10,556)	(22,468)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 522,582	$ 149,059	$ 1,458,612	$ 447,783

EARNINGS PER COMMON SHARE:

Basic	$	1.25	$	0.46	$	3.75	$	1.42
Assuming dilution	$	1.13	$	0.43	$	3.40	$	1.32
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.060	$	0.050	$	0.170	$	0.145
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):								
Basic		417,569		322,101		389,136		314,425
Assuming dilution		483,273		367,639		450,680		352,210

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2006	2005
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 1,531,961	$ 495,777
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,041,246	649,907
Unrealized (gains) losses on derivatives	(453,347)	135,175
Deferred income taxes	963,136	284,977
Amortization of loan costs and bond discount	14,952	10,576
Realized (gains) losses on financing derivatives	(96,377)	
Stock-based compensation	78,200	10,172
Gain on sale of investment in Pioneer Drilling Company	(117,396)	
Income from equity investments	(9,187)	(2,171)
Loss on repurchases or exchanges of Chesapeake senior notes		70,047
Premiums paid for repurchasing of senior notes		(61,023)
Other	(3,556)	(503)
Change in assets and liabilities	32,787	(15,589)
Cash provided by operating activities	2,982,419	1,577,345
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(3,089,710)	(1,932,934)
Exploration and development of oil and natural gas properties	(2,583,841)	(1,488,145)
Additions to buildings and other fixed assets	(406,752)	(156,978)
Additions to drilling rig equipment	(340,814)	(42,056)
Proceeds from sale of investment in Pioneer Drilling Company	158,890	
Proceeds from sale of drilling rigs and equipment	187,500	
Additions to investments	(537,703)	(37,273)
Acquisition of trucking company, net of cash acquired	(45,166)	
Deposits for acquisitions	(12,070)	
Other	1,661	2,342
Cash used in investing activities	(6,668,005)	(3,655,044)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	7,058,000	3,561,000
Payments on long-term borrowings	(5,666,000)	(3,620,000)
Proceeds from issuance of senior notes, net of offering costs	969,193	1,765,383
Proceeds from issuance of common stock, net of offering costs	803,720	289,391
Proceeds from issuance of preferred stock, net of offering costs	557,627	782,368
Purchases or exchanges of Chesapeake senior notes		(556,407)
Common stock dividends	(61,829)	(45,771)
Preferred stock dividends	(62,541)	(17,315)
Financing costs of credit facility	(5,079)	(4,672)
Purchases of treasury shares	(86,185)	(4,000)
Derivative settlements	(68,361)	

Net increase in outstanding payments in excess of cash balance	43,250	33,751
Cash received from exercise of stock options and warrants	71,254	19,940
Excess tax benefit from stock-based compensation	85,649	
Other financing costs	(12,423)	(5,763)
Cash provided by financing activities	3,626,275	2,197,905
Net increase (decrease) in cash and cash equivalents	(59,311)	120,206
Cash and cash equivalents, beginning of period	60,027	6,896
Cash and cash equivalents, end of period	$ 716	$ 127,102

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30,	
	2006	**2005**
	($ in thousands)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 245,190	$ 162,218
Income taxes, net of refunds received	$	$
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

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, with estimated proved reserves of approximately 618 bcfe and daily production of approximately 83 mmcfe.

For the nine months ended September 30, 2006 and 2005, holders of our 6.0% cumulative convertible preferred stock converted 99,310 and 1,835 shares, respectively, into 482,694 and 8,918 shares, respectively, of common stock.

For the nine months ended September 30, 2006 and 2005, holders of our 4.125% cumulative convertible preferred stock exchanged 2,750 and 178,675 shares, respectively, for 172,594 and 11,441,008 shares, respectively, of common stock in privately negotiated exchanges.

For the nine months ended September 30, 2006 and 2005, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 and 697,724 shares, respectively, for 1,140,223 and 4,354,439 shares, respectively, of common stock in privately negotiated exchanges.

During the nine months ended September 30, 2006, we completed tender offers for our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock, issuing 5.2 million shares of our common stock in exchange for 83,245 shares of the 4.125% preferred stock, which represented 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, and 5.0 million shares of our common stock in exchange for 804,048 shares of the 5.0% (Series 2003) preferred stock, which represented 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding. No cash was received or paid in connection with these transactions.

As of September 30, 2006 and 2005, dividends payable on our common and preferred stock were $51.1 million and $28.7 million, respectively.

For the nine months ended September 30, 2006 and 2005, oil and natural gas properties were adjusted by $177.7 million and $253.2 million, respectively, for net income tax liabilities related to acquisitions.

For the nine months ended September 30, 2006 and 2005, $72.6 million and $22.4 million, respectively, of accrued exploration and development costs were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to net oil and natural gas properties of $13.7 million and $8.0 million for the nine months ended September 30, 2006 and 2005, respectively, for asset retirement obligations.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	($ in thousands)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,576,621	$ 490,906
Issuance of 6.25% mandatory convertible preferred stock	575,000	
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)		460,000
Issuance of 4.50% cumulative convertible preferred stock		345,000
Exchange of common stock for 85,995 and 178,675 shares of 4.125% preferred stock	(85,995)	(178,675)
Exchange of common stock for 987,321 and 697,724 shares of 5.00% preferred stock (Series 2003)	(98,732)	(69,772)
Exchange of common stock for 99,310 and 1,835 shares of 6.00% preferred stock	(4,966)	(92)
Balance, end of period	1,961,928	1,047,367
COMMON STOCK:		
Balance, beginning of period	3,755	3,169
Issuance of 28,750,000 and 9,200,000 shares of common stock	288	92
Issuance of 1,375,989 shares of common stock for the purchase of Chaparral Energy, Inc. common stock	14	
Exchange of 12,016,423 and 15,804,365 shares of common stock for preferred stock	120	158
Exercise of stock options and warrants	67	38
Restricted stock grants	135	37
Balance, end of period	4,379	3,494
PAID-IN CAPITAL:		
Balance, beginning of period	3,803,312	2,440,105
Issuance of common stock	834,900	300,932
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock	39,986	
Exchange of 12,016,423 and 15,804,365 shares of common stock for preferred stock	189,572	248,381
Equity-based compensation	88,989	78,943
Adoption of SFAS 123(R)	(89,242)	
Offering expenses	(48,829)	(34,302)
Exercise of stock options and warrants	71,187	19,902
Release of 6,500,000 shares from treasury stock upon exercise of stock options	(75,102)	
Tax benefit from exercise of stock options and restricted stock	85,649	17,397
Preferred stock conversion/exchange expenses	(788)	(103)
Balance, end of period	4,899,634	3,071,255
RETAINED EARNINGS:		
Balance, beginning of period	1,100,841	262,987
Net income	1,531,961	495,777
Dividends on common stock	(68,789)	(46,612)
Dividends on preferred stock	(68,798)	(25,726)
Balance, end of period	2,495,215	686,426
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(194,972)	20,425
Hedging activity	1,143,738	(546,305)
Marketable securities activity	(86,525)	44,440

Balance, end of period	862,241	(481,440)
UNEARNED COMPENSATION:		
Balance, beginning of period	(89,242)	(32,618)
Restricted stock granted		(78,148)
Amortization of unearned compensation		16,075
Adoption of SFAS 123(R)	89,242	
Balance, end of period		(94,691)
TREASURY STOCK COMMON:		
Balance, beginning of period	(25,992)	(22,091)
Purchase of 2,707,471 and 257,220 shares of treasury stock	(86,185)	(4,000)
Release of 6,500,000 shares upon exercise of stock options	75,102	
Release of 221,759 shares for company benefit plans	6,498	
Balance, end of period	(30,577)	(26,091)
TOTAL STOCKHOLDERS EQUITY	$ 10,192,820	$ 4,206,320

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	($ in thousands)			
Net income	$ 548,335	$ 176,988	$ 1,531,961	$ 495,777
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $451,888,000, ($345,346,000), $1,084,370,000 and ($389,909,000)	750,588	(600,807)	1,799,636	(678,334)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($105,162,000), $40,815,000, ($268,896,000) and $39,798,000	(174,040)	71,007	(444,770)	69,238
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($64,099,000), $36,307,000, ($125,599,000) and $36,092,000	(107,730)	63,165	(211,128)	62,791
Unrealized gain (loss) on marketable securities, net of income taxes of ($2,336,000), $12,046,000, ($7,995,000) and $25,544,000	(3,926)	20,957	(13,439)	44,440
Reclassification of gain on sales of investments, net of income taxes of $0, $0, ($45,824,000) and $0			(73,086)	
Comprehensive income	$ 1,013,227	$ (268,690)	$ 2,589,174	$ (6,088)

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission. Chesapeake s 2005 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three and nine months ended September 30, 2006 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and nine months ended September 30, 2006 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2005 (the Prior Quarter and the Prior Period , respectively).

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. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in oil and natural gas exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses or production expenses.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2006 and 2005, we recorded the following stock-based compensation ($ in thousands):

	Restricted Stock		Stock Options		Total	
For the Three Months Ended September 30:	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Production expenses	$ 2,742	$	$ 143	$	$ 2,885	$
General and administrative expenses	7,949	4,315	530	934	8,479	5,249
Oil and natural gas properties	9,452	3,676	492	1,390	9,944	5,066
Total	$ 20,143	$ 7,991	$ 1,165	$ 2,324	$ 21,308	$ 10,315
For the Nine Months Ended September 30:						
Production expenses	$ 5,191	$	$ 523	$	$ 5,714	$
General and administrative expenses	18,066	8,837	3,190	1,335	21,256	10,172
Employee retirement expense	35,720		15,510		51,230	
Oil and natural gas properties	17,739	7,395	1,755	1,390	19,494	8,785
Total	$ 76,716	$ 16,232	$ 20,978	$ 2,725	$ 97,694	$ 18,957

The impact to income before income taxes of adopting SFAS 123(R) for the Current Quarter and the Current Period was a reduction of $0.6 million and $2.5 million, respectively. 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 nine months ended September 30, 2006, we reported $85.6 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

Pro forma Disclosures

Prior to January 1, 2006, we accounted for our employee and non-employee director stock options using the intrinsic value method prescribed by APB 25. As required by SFAS 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for the three and nine months ended September 30, 2005 ($ in thousands, except per share amounts):

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net Income:		
As reported	$ 176,988	$ 495,777
Add: Stock-based compensation expense included in reported net income, net of income tax	3,333	6,459
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of income tax	(5,218)	(13,176)
Pro forma net income	$ 175,103	$ 489,060
Basic earnings per common share:		
As reported	$ 0.46	$ 1.42

Pro forma	$	0.46	$	1.40
Diluted earnings per common share:				
As reported	$	0.43	$	1.32
Pro forma	$	0.42	$	1.30

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is four or five years from the date of grant for employees and three years for non-employee directors.

A summary of the status of the unvested shares of restricted stock as of September 30, 2006, and changes during the Current Period, is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2006	5,805,210	$ 18.38
Granted	14,183,418	32.12
Vested	(2,794,835)	19.73
Forfeited	(315,948)	25.76
Unvested shares as of September 30, 2006	16,877,845	$ 29.57

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $85.4 million.

Included in the 14.2 million shares of restricted stock granted during the Current Period are 9.9 million shares of restricted stock granted during the Current Quarter to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in three years with the remaining 50% vesting in five years.

As of September 30, 2006, there was $478.6 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 4.09 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to restricted stock of $1.3 million, $1.5 million, $4.3 million and $1.6 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides information related to stock option activity during the Current Period:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in thousands)
Outstanding at January 1, 2006	20,256,013	$ 6.14		
Exercised	(13,198,705)	5.32		
Forfeited	(72,713)	9.18		
Outstanding at September 30, 2006	6,984,595	$ 7.65	5.54	$ 149,081
Exercisable at September 30, 2006	5,688,614	$ 7.31	5.30	$ 123,403

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

The aggregate intrinsic value of stock options exercised during the Current Period was approximately $345.0 million.

As of September 30, 2006, there was $2.5 million of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of 0.52 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $2.8 million, $7.4 million, $81.3 million and $15.8 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2005.

2. 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 September 30, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or natural gas from a specified delivery point. We currently have basis protection swaps covering six different

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

delivery points, four in the Mid-Continent and two in the Appalachian Basin, which correspond to the actual prices we receive for much of our natural gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future natural gas price differentials. As of September 30, 2006, the fair value of our basis protection swaps was $178.8 million. As of September 30, 2006, our Mid-Continent basis protection swaps cover approximately 29% of our anticipated remaining Mid-Continent natural gas production in 2006, 25% in 2007, 18% in 2008 and 13% in 2009. As of September 30, 2006, our Appalachian Basin basis protection swaps cover approximately 74% of our anticipated Appalachian Basin natural gas production in 2007, 65% in 2008 and 30% in 2009.

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $301.4 million, ($122.6) million, $807.1 million and ($126.6) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $238.5 million, ($104.0) million, $452.6 million and ($137.1) million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $171.8 million, ($99.5) million, $336.7 million and ($98.9) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

The estimated fair values of our oil and natural gas derivative instruments as of September 30, 2006 and December 31, 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2006	December 31, 2005
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ 1,234,681	$ (1,047,094)
Natural gas basis protection swaps	178,832	307,308
Fixed-price natural gas cap-swaps	69,136	(161,056)
Fixed-price natural gas counter-swaps	6,646	37,785
Natural gas call options (a)	(21,816)	(21,461)
Fixed-price natural gas collars	(7,016)	(9,374)
Fixed-price natural gas locked swaps	(16,333)	(34,229)
Floating-price natural gas swaps		2,607
Fixed-price oil swaps	13,547	(16,936)
Fixed-price oil cap-swaps	18,317	(3,364)
Estimated fair value	$ 1,475,994	$ (945,814)

(a) After adjusting for $49.6 million and $23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of September 30, 2006 and December 31, 2005 was $27.8 million and $1.6 million, respectively.

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Based upon the market prices at September 30, 2006, we expect to transfer approximately $530.2 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 September 30, 2006 are expected to mature by December 31, 2009.

We have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for each of these facilities is May 2010. 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. Both of the hedging facilities are subject to a 1.0% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of September 30, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $252.1 million under one of the facilities and an asset of $823.2 million under the other facility. As of November 3, 2006, the fair market value of the same transactions was an asset of approximately $152.2 million and $255.5 million, respectively. 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 natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

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

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

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The following details the assumed CNR derivatives remaining as of September 30, 2006:

	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 September 30, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
4Q 2006	10,626,000	$ 4.86	$	$	Yes	$ (9,313)
1Q 2007	10,350,000	4.82			Yes	(30,297)
2Q 2007	10,465,000	4.82			Yes	(24,548)
3Q 2007	10,580,000	4.82			Yes	(26,672)
4Q 2007	10,580,000	4.82			Yes	(33,722)
1Q 2008	9,555,000	4.68			Yes	(39,074)
2Q 2008	9,555,000	4.68			Yes	(23,387)
3Q 2008	9,660,000	4.68			Yes	(24,581)
4Q 2008	9,660,000	4.66			Yes	(29,997)
1Q 2009	4,500,000	5.18			Yes	(14,498)
2Q 2009	4,550,000	5.18			Yes	(7,627)
3Q 2009	4,600,000	5.18			Yes	(8,162)
4Q 2009	4,600,000	5.18			Yes	(10,574)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(2,538)
2Q 2009	910,000		4.50	6.00	Yes	(1,268)
3Q 2009	920,000		4.50	6.00	Yes	(1,375)
4Q 2009	920,000		4.50	6.00	Yes	(1,835)
Total Natural Gas						$ (289,468)

Subsequent to September 30, 2006, Chesapeake lifted a portion of its fourth quarter 2006 and full-year 2007, 2008 and 2009 hedges and as a result received $407 million in cash from its hedging counterparties. The gain will be recorded in accumulated other comprehensive income and in unrealized oil and natural gas sales based on the designation of the hedges. The gain will be recognized in realized oil and natural gas sales in the month of the hedged production.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed 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 certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.6) million, $0.8 million, $0.9 million and $2.6 million in the Current

Quarter, Prior Quarter, Current Period and

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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Prior Period, 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 condensed consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $2.5 million, ($1.2) million, $0.8 million and $1.9 million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

As of September 30, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,919)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(6,301)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,456)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(7,305)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(3,308)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(7,124)
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points	(3,178)
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points	(172)
				$ (36,763)

In the Current Period, we closed three interest rate swaps for gains totaling $3.0 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

To mitigate our short-term exposure to rising interest rates on a portion of our long-term debt that has been converted to floating-rate, we have entered into zero-cost collar transactions. These collars contain a fixed floor rate (put) and fixed ceiling rate (call). If LIBOR exceeds the ceiling rate or falls below the floor rate, Chesapeake pays the fixed rate and receives LIBOR. If LIBOR is between the ceiling and floor rates, no payments are due from either party. As of September 30, 2006, we were a party to the following zero-cost interest rate collars:

Payment Dates	Notional Amount	LIBOR Floor	LIBOR Ceiling
July 2007 January 2010	$150,000,000	4.53%	5.37%
June 2007 December 2009	$150,000,000	4.53%	5.37%
August 2007 February 2010	$250,000,000	4.53%	5.37%
July 2007 January 2010	$250,000,000	4.53%	5.37%

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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at September 30, 2006 and December 31, 2005 were \$6.421 billion and \$5.429 billion, respectively, compared to approximate fair values of \$6.317 billion and \$5.582 billion, respectively. The carrying amounts for our convertible preferred stock as of September 30, 2006 and December 31, 2005 were \$1.962 billion and \$1.577 billion, respectively, compared to approximate fair values of \$1.950 billion and \$1.686 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Accounts receivable potentially subject us to concentrations of credit risk as well. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

3. Contingencies and Commitments

Litigation

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

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 July 1, 2006. The term of the agreement is automatically extended for one additional year on each January 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 and benefits would continue during the remaining term of the agreement. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009 and provide for the continuation of salary for one year in the event of termination of employment without cause. The company s employment agreements with the executive officers provide for payments in the event of a change of control. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation and three times the value of the prior year s benefits, plus a tax gross-up payment, upon the happening of certain events following a change of control, and the company will also provide him office space and secretarial and accounting support for a period of 12 months thereafter. The chief operating officer, chief financial officer and other executive officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year in the event of a change of control. Any stock-based awards held by an executive officer will immediately become 100% vested upon termination of employment without cause or upon a change of control event.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 September 30, 2006.

Rig Leases

In September 2006, our wholly owned subsidiary, Nomac Drilling Corporation, sold 18 of its drilling rigs and related equipment for $187.5 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for an initial term of eight years from October 1, 2006 for rental payments of $26.0 million annually. Nomac s lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. This transaction was recorded as a sale and operating leaseback, with an aggregate deferred gain of $14.8 million on the sale which will be amortized to service operations expense over the lease term. Under the rig lease, we have the option to purchase the rigs on September 30, 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.

Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of September 30, 2006, minimum future rig lease payments were as follows (in thousands):

2006	$ 6,130
2007	25,993
2008	25,993
2009	25,993
2010	25,993
Thereafter	97,478
Total	$ 207,580

Other Commitments

As of September 30, 2006, Chesapeake s wholly owned subsidiary, Nomac Drilling Corporation, had contracted to acquire 22 rigs to be constructed during 2006 and 2007. The total remaining cost of the rigs will be approximately $200 million.

Currently, Chesapeake has contracts with various drilling contractors to use approximately 50 rigs in 2006 with terms of one to three years. As of September 30, 2006, the minimum aggregate drilling rig commitment was approximately $450 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to $25 million each through December 31, 2009. At September 30, 2006, there was a $19.5 million loan outstanding under this agreement.

As of September 30, 2006, Chesapeake had agreed to acquire 16,600 net acres of Barnett Shale leasehold from the Dallas/Fort Worth International Airport Board and the cities of Dallas and Fort Worth for $181 million in cash and a 25% royalty (subject to an assignment of a 20% interest to various minority and women businesses that will participate with Chesapeake in the development of the lease). This transaction closed on October 5, 2006.

As of September 30, 2006, Chesapeake had agreed to acquire oil and natural gas properties and mid-stream natural gas systems from Dale Resources, L.L.C. et al. for approximately $220 million of which $10.9 million was paid in the Current Quarter. This transaction closed on October 12, 2006.

4. Net Income Per Share

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

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

For the Current Quarter, Prior Quarter and the Prior Period, outstanding options to purchase 0.1 million shares of common stock at a weighted average exercise price of $30.63, $30.59 and $29.85, respectively, were antidilutive because the exercise price of the options was greater than the average market price of the common stock during the period.

For the Prior Quarter and Prior Period, diluted shares do not include the common stock equivalent of our 4.125% preferred stock outstanding prior to conversion (convertible into 3,913,918 and 8,403,579 shares, respectively), and the preferred stock adjustment to net income does not include $14.7 million and $22.9 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the Prior Quarter and Prior Period, diluted shares do not include the common stock equivalent of our 5.0% (Series 2003) preferred stock outstanding prior to conversion (convertible into 3,603,567 and 4,034,450 shares, respectively), and the preferred stock adjustment to net income does not include $4.0 million and $5.8 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the Prior Quarter and the Prior Period, diluted shares do not include the common stock equivalent of our 4.5% preferred stock outstanding prior to conversion (convertible into 1,443,236 and 486,365 shares, respectively), and the preferred stock adjustment to net income does not include $0.7 million and $0.7 million, respectively, of dividends related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

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Reconciliations for the three months ended September 30, 2006 and 2005 and the nine months ended September 30, 2006 and 2005 are as follows:

For the Three Months Ended September 30, 2006:	Income (Numerator)	Shares (Denominator)	Per Share Amount
	($ in thousands, except per share data)		
Basic EPS:			
Income available to common shareholders	$ 522,582	417,569	$ 1.25
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		184	
Common shares assumed issued for 4.50% convertible preferred stock		7,811	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		235	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		17,856	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		14,717	
Common shares assumed issued for 6.25% convertible preferred stock		19,100	
Employee stock options		4,248	
Restricted stock		1,553	
Preferred stock dividends	25,753		
Diluted EPS Income available to common shareholders and assumed conversions	$ 548,335	483,273	$ 1.13
For the Three Months Ended September 30, 2005:			
Basic EPS:			
Income available to common shareholders	$ 149,059	322,101	$ 0.46
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		8,082	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		6,262	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		17,853	
Common shares assumed issued for 6.00% convertible preferred stock		492	
Employee stock options		11,006	
Restricted stock		1,843	
Preferred stock dividends	8,498		
Diluted EPS Income available to common shareholders and assumed conversions	$ 157,557	367,639	$ 0.43

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	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the Nine Months Ended September 30, 2006:	($ in thousands, except per share data)		
Basic EPS:			
Income available to common shareholders	$ 1,458,612	389,136	$ 3.75
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		184	
Common shares assumed issued for 4.50% convertible preferred stock		7,811	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		235	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		17,856	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		14,717	
Common shares assumed issued for 6.25% convertible preferred stock		6,498	
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,			
6.00% convertible preferred stock		137	
4.125% convertible preferred stock		2,795	
5.00% convertible preferred stock (Series 2003)		2,807	
Employee stock options		6,714	
Restricted stock		1,790	
Loss on redemption of preferred stock	10,556		
Preferred stock dividends	62,793		
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,531,961	450,680	$ 3.40
For the Nine Months Ended September 30, 2005:			
Basic EPS:			
Income available to common shareholders	$ 447,783	314,425	$ 1.42
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		8,082	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		6,262	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		10,739	
Common shares assumed issued for 6.00% convertible preferred stock		492	
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,			
6.00% convertible preferred stock		5	
Employee stock options		10,810	
Restricted stock		1,382	
Warrants assumed in Gothic acquisition		13	
Preferred stock dividends	18,546		

Diluted EPS Income available to common shareholders and assumed conversions	$ 466,329	352,210	$ 1.32

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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5. Stockholders Equity

The following is a summary of the changes in our common shares outstanding for the nine months ended September 30, 2006 and 2005:

	2006	2005
	(in thousands)	
Shares outstanding at January 1	375,511	316,941
Stock option and warrant exercises	6,676	3,820
Restricted stock issuances	13,530	3,619
Preferred stock conversions/exchanges	12,016	15,804
Common stock issuances	28,750	9,200
Common stock issued for the purchase of Chaparral Energy, Inc. common stock	1,376	
Shares outstanding at September 30	437,859	349,384

The following is a summary of the changes in our preferred shares outstanding for the nine months ended September 30, 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, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,300
Conversion/exchange of preferred for common stock	(99)	(987)	(86)				
Shares outstanding at September 30, 2006		39	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		
Conversion/exchange of preferred for common stock	(2)	(698)	(178)				
Shares outstanding at September 30, 2005	101	1,027	135	4,600	3,450		

In connection with the exchanges and conversions noted above, we recorded a loss of $17.7 million, $10.6 million and $22.5 million in the Prior Quarter, Current Period and Prior Period, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

During the Current Period, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of our common stock.

During the Current Period, holders of our 4.125% cumulative convertible preferred stock exchanged 2,750 shares for 172,594 shares of our common stock.

During the Current Period, the remaining 99,310 shares of our 6.0% preferred stock were converted into or exchanged for 482,694 shares of common stock.

During the Current Period, we completed tender offers for our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock, issuing 5.2 million shares of our common stock in exchange for 83,245 shares of the

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4.125% preferred stock, which represented 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, and 5.0 million shares of our common stock in exchange for 804,048 shares of the 5.0% (Series 2003) preferred stock, which represented 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding. No cash was received or paid in connection with these transactions.

In June 2006, we issued 2,000,000 shares of 6.25% mandatory convertible preferred stock, par value $0.01 per share and liquidation preference $250 per share, in a public offering for net proceeds of $484.8 million. We issued an additional 300,000 shares of such preferred stock in July 2006, upon the exercise of the underwriters option to purchase the additional shares, for net proceeds of $72.8 million.

In June 2006, we issued 25,000,000 shares of Chesapeake common stock at $29.05 per share in a public offering for net proceeds of $698.9 million. We issued an additional 3,750,000 shares in July 2006 at the same price pursuant to the underwriters exercise of their overallotment option to purchase the additional shares for net proceeds of $104.8 million.

In the Current Quarter, we issued 9.9 million shares of restricted stock to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in three years with the remaining 50% vesting in five years.

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, with estimated proved reserves of approximately 618 bcfe and daily production of approximately 83 mmcfe.

6. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of September 30, 2006 and December 31, 2005:

	September 30, 2006	December 31, 2005
	($ in thousands)	
7.5% Senior Notes due 2013	$ 363,823	$ 363,823
7.625% Senior Notes due 2013	500,000	
7.0% Senior Notes due 2014	300,000	300,000
7.5% Senior Notes due 2014	300,000	300,000
7.75% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	600,000
6.875% Senior Notes due 2016	670,437	670,437
6.5% Senior Notes due 2017	1,100,000	600,000
6.25% Senior Notes due 2018	600,000	600,000
6.875% Senior Notes due 2020	500,000	500,000
2.75% Contingent Convertible Senior Notes due 2035 (a)	690,000	690,000
Revolving bank credit facility	1,464,000	72,000
Discount on senior notes	(103,939)	(95,577)
Discount for interest rate derivatives (b)	(23,621)	(11,349)
Total senior notes and long-term debt	$ 7,861,108	$ 5,489,742

(a) The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030, or upon a fundamental change, at

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

100% of the principal amount of these notes. The notes are convertible, at the holder s option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the nine-month period ending May 14, 2016, under certain conditions. We may redeem the convertible senior notes on or after November 15, 2015 at a redemption price of 100% of the principal amount of such notes.

(b) See Note 2 for a description of these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $863.8 million is due.

There were no repurchases or exchanges of Chesapeake debt in the Current Quarter or the Current Period. The following table sets forth the losses we incurred in connection with repurchases of senior notes in the Prior Quarter and Prior Period, respectively ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Three Months Ended September 30, 2005:	**Retired**	**Premium**	**Other(a)**	**Total**
8.125% Senior Notes due 2011	$ 7.6	$ 0.5	$ 0.1	$ 0.6
9.0% Senior Notes due 2012	1.1	0.1	0.0	0.1
	$ 8.7	$ 0.6	$ 0.1	$ 0.7
For the Nine Months Ended September 30, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 556.4	$ 59.5	$ 10.5	$ 70.0

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

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006 and to $2.5 billion in September 2006. As of September 30, 2006, we had $1.464 billion in outstanding borrowings under our facility and utilized $6.2 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 1.87 to 1 at September 30, 2006. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

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

7. Segment Information

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production segment and oil and natural gas marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, compressing, transporting and selling natural gas and crude oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations, which were considered a part of the exploration and production segment prior to 2006. These service operations are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

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 $631.0 million, $617.4 million, $1.919 billion and

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$1.486 billion for the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. The following table presents selected financial information for Chesapeake s operating segments. Our drilling rig and trucking service operations are presented in Other Operations for all periods presented.

For the Three Months Ended September 30, 2006:	Exploration and Production	Marketing	Other Operations ($ in thousands)	Intercompany Eliminations	Consolidated Total
Revenues	$ 1,493,226	$ 1,029,126	$ 98,401	$ (691,342)	$ 1,929,411
Intersegment revenues		(631,012)	(60,330)	691,342	
Total revenues	$ 1,493,226	$ 398,114	$ 38,071	$	$ 1,929,411
Income before income taxes	$ 866,789	$ 9,661	$ 33,900	$ (25,941)	$ 884,409
For the Three Months Ended September 30, 2005:					
Revenues	$ 720,928	$ 979,281	$ 16,405	$ (633,771)	$ 1,082,843
Intersegment revenues		(617,366)	(16,405)	633,771	
Total revenues	$ 720,928	$ 361,915	$	$	$ 1,082,843
Income before income taxes	$ 271,835	$ 6,887	$ 1,823	$ (1,823)	$ 278,722
For the Nine Months Ended September 30, 2006:					
Revenues	$ 4,190,430	$ 3,089,348	$ 218,909	$ (2,040,693)	$ 5,457,994
Intersegment revenues		(1,919,257)	(121,436)	2,040,693	
Total revenues	$ 4,190,430	$ 1,170,091	$ 97,473	$	$ 5,457,994
Income before income taxes	$ 2,448,286	$ 29,099	$ 67,653	$ (49,941)	$ 2,495,097
For the Nine Months Ended September 30, 2005:					
Revenues	$ 2,032,271	$ 2,368,502	$ 39,587	$ (1,526,049)	$ 2,914,311
Intersegment revenues		(1,486,462)	(39,587)	1,526,049	
Total revenues	$ 2,032,271	$ 882,040	$	$	$ 2,914,311
Income before income taxes	$ 764,200	$ 16,554	$ 4,638	$ (4,638)	$ 780,754
As of September 30, 2006:					
Total assets	$ 22,669,668	$ 667,399	$ 532,414	$ (474,560)	$ 23,394,921
As of December 31, 2005:					
Total assets	$ 15,722,795	$ 688,747	$ 305,875	$ (598,955)	$ 16,118,462

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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8. Acquisitions

Oil and Natural Gas Properties

The following table describes oil and natural gas property acquisitions of proved and unproved properties that we completed in the Current Period ($ in millions):

Quarter	Acquired From	Location of Properties	Amount
First	Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
	Tulsa-based oil and gas company	Texas Gulf Coast and Mid-Continent	146
	Houston-based oil and gas company	Texas Gulf Coast	125
	Tulsa-based oil and gas company	Ark-La-Tex	70
	Houston-based oil and gas company	Various	53
	Dallas-based oil and gas company	Mid-Continent	30
	Other	Various	297
Second	Dallas-based oil and gas company	Permian	375
	Oklahoma City-based oil and gas company	Permian	175
	Other	Various	196
Third	Four Sevens Oil Co., Ltd. and Sinclair Oil Corporation	Barnett Shale	845(a)
	Dallas-based oil and gas company	Ark-La-Tex and Texas Gulf Coast	200
	Houston-based oil and gas company	Texas Gulf Coast	111
	Other	Various	285
	Total oil and natural gas acquisitions		$ 3,180

(a) Includes $55 million related to mid-stream natural gas systems which was allocated to other property and equipment.

We also recorded approximately $177.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

Drilling Rigs and Oilfield Trucks

In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. In addition to the cash purchase price, we recorded approximately $17.0 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. Of the total $64.5 million purchase price, $27.1 million was allocated to tangible equipment, $11.0 million to intangibles and $26.4 million to goodwill. The amounts allocated to intangibles and goodwill are included in long-term assets in the accompanying condensed consolidated balance sheet. Goodwill is not amortized but is subject to an annual assessment of impairment. In February 2006, we acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for $150 million. In July 2006, we acquired a drilling contractor and an affiliated trucking company in the Appalachian Basin for approximately $70 million in cash.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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Other

In August 2006, we invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, with estimated proved reserves of approximately 618 bcfe and daily production of 83 mmcfe.

9. Full-Cost Ceiling Test

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission (SEC) on a quarterly and annual basis. This 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 (including the impact of cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to the 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.

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. Such derivative contracts, which consist of swaps and collars, and the related production volumes are discussed in Note 2 and in Item 3. *Quantitative and Qualitative Disclosures About Market Risk*. Based on spot prices for oil and natural gas as of September 30, 2006, these cash flow hedges increased the full cost ceiling by $4.4 billion, thereby reducing any potential ceiling test write-down by the same amount.

At December 31, 2005, Chesapeake s net book value of oil and natural gas properties less deferred income taxes was below the calculated ceiling by approximately $6.5 billion. From December 31, 2005 to September 30, 2006, spot natural gas prices decreased by approximately 59% from $10.08 to $4.18 per mcf. As a result, as of September 30, 2006, our ceiling test calculation indicated an impairment of our oil and natural gas properties of approximately $415 million, net of income tax. However, natural gas prices subsequent to September 30, 2006, have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting in the third quarter of 2006.

10. 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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In December 2004, the FASB issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, *Accounting for Stock-Based Compensation*. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

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

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

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

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, SFAS 157 will have on our financial position, results of operations or cash flows.

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

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ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Overview

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 three and nine months ended September 30, 2006 (the Current Quarter and the Current Period) and the three and nine months ended September 30, 2005 (the Prior Quarter and the Prior Period):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Net Production:				
Oil (mbbls)	2,178	1,926	6,437	5,684
Natural gas (mmcf)	133,822	108,801	387,696	304,060
Natural gas equivalent (mmcfe)	146,890	120,357	426,318	338,164
Oil and Natural Gas Sales ($ in thousands):				
Oil sales	$ 141,687	$ 113,590	$ 404,595	$ 290,332
Oil derivatives realized gains (losses)	(9,660)	(10,937)	(25,695)	(28,654)
Oil derivatives unrealized gains (losses)	28,724	(4,009)	24,825	(5,951)
Total oil sales	160,751	98,644	403,725	255,727
Natural gas sales	811,591	833,992	2,526,168	2,005,670
Natural gas derivatives realized gains (losses)	311,090	(111,668)	832,769	(97,955)
Natural gas derivatives unrealized gains (losses)	209,794	(100,040)	427,768	(131,171)
Total natural gas sales	1,332,475	622,284	3,786,705	1,776,544
Total oil and natural gas sales	$ 1,493,226	$ 720,928	$ 4,190,430	$ 2,032,271
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 65.05	$ 58.98	$ 62.85	$ 51.08
Natural gas ($ per mcf)	$ 6.06	$ 7.67	$ 6.52	$ 6.60
Natural gas equivalent ($ per mcfe)	$ 6.49	$ 7.87	$ 6.87	$ 6.79
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 60.62	$ 53.30	$ 58.86	$ 46.04
Natural gas ($ per mcf)	$ 8.39	$ 6.64	$ 8.66	$ 6.27
Natural gas equivalent ($ per mcfe)	$ 8.54	$ 6.85	$ 8.77	$ 6.42
Other Operating Income (a) ($ in thousands):				
Oil and natural gas marketing	$ 13,641	$ 8,405	$ 38,570	$ 21,251
Service operations	$ 19,250	$	$ 48,548	$
Other Operating Income ($ per mcfe):				
Oil and natural gas marketing	$ 0.09	$ 0.07	$ 0.09	$ 0.06
Service operations	$ 0.13	$	$ 0.11	$
Expenses ($ per mcfe):				
Production expenses	$ 0.84	$ 0.67	$ 0.85	$ 0.66
Production taxes	$ 0.28	$ 0.44	$ 0.30	$ 0.40
General and administrative expenses	$ 0.25	$ 0.13	$ 0.23	$ 0.12
Oil and natural gas depreciation, depletion and amortization	$ 2.34	$ 1.92	$ 2.29	$ 1.84
Depreciation and amortization of other assets	$ 0.18	$ 0.11	$ 0.17	$ 0.10
Interest expense (b)	$ 0.52	$ 0.48	$ 0.52	$ 0.47
Interest Expense ($ in thousands):				
Interest expense	$ 75,100	$ 58,206	$ 221,832	$ 160,209
Interest rate derivatives realized (gains) losses	1,555	(843)	(852)	(2,639)
Interest rate derivatives unrealized (gains) losses	(2,543)	1,230	(754)	(1,947)

Total interest expense	$ 74,112	$ 58,593	$ 220,226	$ 155,623
Net Wells Drilled	401	218	985	583
Net Producing Wells as of the End of the Period	18,511	9,313	18,511	9,313

(a) Includes revenue and operating costs.

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

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Chesapeake is the third largest independent producer of natural gas in the United States. We own interests in approximately 33,700 producing oil and natural gas wells that are currently producing approximately 1.66 bcfe per day, which includes approximately 0.1 bcfe per day of previously curtailed production that is now back on line. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the U.S. east of the Rocky Mountains. Our most important operating area has historically been in various conventional plays in the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At September 30, 2006, 47% of our estimated proved oil and natural gas reserves were located in the Mid-Continent. During the past four years, we have also built significant positions in various conventional and unconventional plays 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 Texas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Fayetteville Shale in Arkansas, the Barnett and Woodford Shales in West Texas and the Conasauga, Floyd and Chattanooga Shales of Alabama.

Oil and natural gas production for the Current Quarter was 146.9 bcfe, an increase of 26.5 bcfe, or 22% over the 120.4 bcfe produced in the Prior Quarter. We have increased our production for 21 consecutive quarters. During these 21 quarters, Chesapeake s U.S. production has increased 308% for an average compound quarterly growth rate of 6.9% and an average compound annual growth rate of 30.5%.

In addition to increased oil and natural gas production, the prices we received were higher in the Current Quarter than in the Prior Quarter. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $8.54 per mcfe in the Current Quarter compared to $6.85 per mcfe in the Prior Quarter. The increase in prices resulted in an increase in revenue of $247.9 million, and increased production resulted in an increase in revenue of $181.8 million, for a total increase in revenue of $429.7 million (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist, thereby contributing to relatively high wellhead price realizations for our production.

During the Current Quarter, Chesapeake continued to lead the nation in drilling activity with an average utilization of 103 operated rigs and 71 non-operated rigs. Through this drilling activity, we drilled 411 (348 net) operated wells and participated in another 353 (53 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 96% for non-operated wells. During the Current Quarter, Chesapeake invested $674 million in operated wells, $119 million in non-operated wells and $162 million in acquiring 3-D seismic data and leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $1.391 billion during the Current Quarter, including amounts paid for unproved leasehold and excluding $96.3 million of deferred income taxes in connection with certain corporate acquisitions. We expect to continue replacing reserves through the drillbit and acquisitions, although the timing and magnitude of future additions are uncertain.

Chesapeake began 2006 with estimated proved reserves of 7.521 tcfe and based on internal estimates ended the Current Quarter with 8.433 tcfe, an increase of 912 bcfe, or 12%. During the Current Period, we replaced 426 bcfe of production with an estimated 1.339 tcfe of new proved reserves, for a reserve replacement rate of 314%. Reserve replacement through the drillbit was 825 bcfe, or 194% of production (including 541 bcfe of positive performance revisions and 387 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and September 30, 2006) and 62% of the total increase. Reserve replacement through the acquisition of proved reserves was 514 bcfe, or 120% of production and 38% of the total increase. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2006 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Chesapeake attributes its strong drilling results and organic growth rates during the first nine months of 2006 (and in this decade) to management s early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry people, land and seismic. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff to approximately 800 employees. Today, the company has more than 4,600 employees, of which approximately 65% work in the company s E&P operations and 35% work in the company s oilfield service operations.

Since 2000, Chesapeake has invested $5.7 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be one of the largest inventories of onshore leasehold (10.5 million net acres) and 3-D seismic (14.7 million acres) in the U.S. On this leasehold, the company has an estimated 25,000 net drilling locations representing an approximate 10-year inventory of drilling projects.

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

This investment complements Chesapeake s direct and indirect drilling rig investments that have served as an effective hedge to higher service costs and have also provided competitive advantages in making acquisitions and in developing the company s own leasehold on a more timely and efficient basis. To date, Chesapeake has invested approximately $254 million to build or acquire 42 drilling rigs and is building 22 additional rigs. Additionally, the company entered into a sale/leaseback transaction to monetize its investment in 18 of its rigs in exchange for cash proceeds of $187.5 million. These rigs are under lease to Chesapeake through 2014 at which time the company has the option to reacquire them. In total, the company s drilling rig fleet should reach 82 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a $69 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake s equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating two rigs and has another eight rigs under construction or on order for delivery in 2006 and 2007.

As of September 30, 2006, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 44% compared to 47% as of December 31, 2005. During the Current Period, we received net proceeds of $2.3 billion through issuances of $575 million of preferred equity, $835 million of common equity and $1.0 billion principal amount of senior notes. We used the net proceeds from these offerings primarily to fund the purchase price for acquisitions and to repay outstanding indebtedness under our revolving bank credit facility. As a result of our debt transactions in 2005 and the Current Period, we have extended the average maturity of our long-term debt to over nine years and have lowered our average interest rate to approximately 6.4%.

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

Liquidity and Capital Resources

Sources and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our drilling capital expenditures for the remainder of 2006 and 2007. Our budget for drilling, land and seismic activities for the remainder of 2006 is currently between $1.1 billion and $1.3 billion. We believe this level of exploration and development will be sufficient to increase our proved oil and natural gas reserves in 2006 and achieve our goal of an organic growth rate of more than 10% over 2005 production and at least a 23% increase in total production (inclusive of acquisitions completed or scheduled to close in 2006 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2006). However, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions, prolonged shut-ins or other factors could cause us to revise our drilling program, which is largely discretionary. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes.

Cash provided by operating activities was $2.982 billion in the Current Period compared to $1.577 billion in the Prior Period. The $1.405 billion increase was primarily due to higher realized prices and higher oil and natural gas production. While a further decline in natural gas prices for the remainder of 2006 and 2007 would affect the amount of cash flow that would be generated from operations, we have 88% and 73% of our expected oil production for the fourth quarter of 2006 and 2007, respectively, hedged at an average NYMEX price of $65.64 and $71.42 per barrel of oil, respectively, and 57% of our expected natural gas production for both the fourth quarter of 2006 and 2007, respectively, hedged at an average NYMEX price of $9.10 and $9.61 per mmbtu, respectively. These levels of hedging provide greater certainty of the cash flow we will receive for a substantial portion of our remaining 2006 and 2007 production. Depending on changes in oil and natural gas futures markets and management s view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. As of September 30, 2006, we had outstanding collateral allocations and pledges of oil and gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our bank credit facility. As of November 3, 2006, we had outstanding transactions with thirteen counterparties, seven of which hold collateral allocations from our bank facility or liens against certain oil and natural gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. As of November 3, 2006, we were not required to post cash or letters of credit with the remaining four counterparties. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

A significant source of liquidity is our $2.5 billion syndicated revolving bank credit facility which matures in February 2011. At November 3, 2006, there was $749.8 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 $7.058 billion and repaid $5.666 billion in the Current Period, and we borrowed $3.561 billion and repaid $3.620 billion in the Prior Period under the credit facility. We incurred $5.1 million and $4.7 million of financing costs related to amendments to the credit facility agreement in the Current Period and the Prior Period, respectively.

We believe that our available cash, cash provided by operating activities and funds available under our revolving bank credit facility will be sufficient to fund our operating, debt service and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future.

The public and institutional markets have been our principal source of long-term financing for acquisitions. We have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future to finance acquisitions. Nevertheless, we caution that ready access to capital on reasonable terms and the availability of desirable acquisition targets at attractive prices are subject to many uncertainties, as explained under Risk Factors in Item 1A of our Form 10-K for the year ended December 31, 2005.

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The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30, 2006		2005	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$ 575.0	$ 557.6	$ 805.0	$ 782.4
Common stock	835.2	803.7	301.0	289.4
Unsecured senior notes guaranteed by subsidiaries	1,000.0	969.2	1,800.0	1,765.4
Total	$ 2,410.2	$ 2,330.5	$ 2,906.0	$ 2,837.2

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

We paid dividends on our common stock of $61.8 million and $45.8 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.05 to $0.06 per share beginning with the dividend paid in July 2006. We paid dividends on our preferred stock of $62.5 million and $17.3 million in the Current Period and the Prior Period, respectively. We received $71.3 million and $19.9 million from the exercise of employee and director stock options and warrants in the Current Period and the Prior Period, respectively. The Current Period amount included $38.3 million paid by Tom L. Ward, our former President and Chief Operating Officer, to exercise all of his stock options following his resignation in February 2006.

In the Current Period, we paid $68.4 million to settle a portion of the derivative liabilities assumed in our November 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 the Current Period, we reported a tax benefit from stock-based compensation of $85.6 million.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $43.3 million and $33.8 million in the Current Period and the Prior Period, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake. The following table shows our purchases and exchanges of senior notes in the Prior Period ($ in millions):

	Senior Notes Activity			
For the Nine Months Ended September 30, 2005:	Retired	Premium	Other(a)	Cash Paid
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$	$ 11.8
8.125% Senior Notes due 2011	245.4	17.3	0.7	263.4
9.0% Senior Notes due 2012	300.0	41.4	0.8	342.2
	$ 556.4	$ 59.5	$ 1.5	$ 617.4

(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.

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Cash used in investing activities increased to $6.668 billion during the Current Period, compared to $3.655 billion during the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Nine Months Ended September 30,	
	2006	2005
Oil and Natural Gas Investing Activities:		
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 960.8	$ 1,175.3
Acquisition of unproved properties	2,128.9	757.6
Exploration and development of oil and natural gas properties	2,041.8	1,294.6
Leasehold acquisitions	456.2	164.6
Geological and geophysical costs	101.8	44.3
Other oil and natural gas activities	(16.0)	(15.4)
Total oil and natural gas investing activities	5,673.5	3,421.0
Other Investing Activities:		
Additions to buildings and other fixed assets	406.8	157.0
Additions to drilling rig equipment (including Martex Drilling Company, L.L.P)	340.8	42.1
Additions to investments	537.7	37.3
Proceeds from sale of investment in Pioneer Drilling Company	(158.9)	
Proceeds from sale of drilling rigs and equipment	(187.5)	
Acquisition of trucking company, net of cash acquired	45.2	
Deposits for acquisitions	12.1	
Other	(1.7)	(2.4)
Total other investing activities	994.5	234.0
Total cash used in (provided by) investing activities	$ 6,668.0	$ 3,655.0

Our accounts receivable are primarily from purchasers of oil and natural gas ($499.0 million at September 30, 2006) and exploration and production companies which own interests in properties we operate ($115.0 million at September 30, 2006). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

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Acquisitions and Financing Transactions

The following table describes investing transactions related to the acquisition of proved and unproved properties that we completed in the Current Period ($ in millions):

Quarter	Acquired From	Location of Properties	Amount
First	Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
	Tulsa-based oil and gas company	Texas Gulf Coast and Mid-Continent	146
	Houston-based oil and gas company	Texas Gulf Coast	125
	Tulsa-based oil and gas company	Ark-La-Tex	70
	Houston-based oil and gas company	Various	53
	Dallas-based oil and gas company	Mid-Continent	30
	Other	Various	297
Second	Dallas-based oil and gas company	Permian	375
	Oklahoma City-based oil and gas company	Permian	175
	Other	Various	196
Third	Four Sevens Oil Co., Ltd. and Sinclair Oil Corporation	Barnett Shale	845(a)
	Dallas-based oil and gas company	Ark-La-Tex and Texas Gulf Coast	200
	Houston-based oil and gas company	Texas Gulf Coast	111
	Other	Various	285
	Total oil and natural gas acquisitions		3,180
	Less cash deposits paid in 2005		(35)
	Total oil and natural gas acquisitions in the Current Period		$ 3,145

(a) Includes $55 million related to mid-stream natural gas systems which was allocated to other property and equipment.

We also recorded approximately $177.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. We recorded approximately $17.0 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. In February 2006, we acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for $150 million. In July 2006, we acquired a drilling contractor and an affiliated trucking company in the Appalachian Basin for approximately $70 million in cash.

In August 2006, we invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, with estimated proved reserves of approximately 618 bcfe and daily production of approximately 83 mmcfe.

During 2005 and continuing in 2006, we have taken several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over nine years with an average interest rate of approximately 6.4%. Maintaining a debt-to-total-capitalization ratio of below 50% and reducing debt per mcfe of proved reserves remain key goals of our business strategy.

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We completed the following significant financing transactions in the Current Period:

First Quarter 2006

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

Second Quarter 2006

- Completed a public exchange of 83,245 shares of our 4.125% cumulative convertible preferred stock, representing 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, for 5.2 million shares of our common stock pursuant to a tender offer. No cash was received or paid in connection with this transaction.
- Completed a public exchange of 804,048 shares of our 5.0% (Series 2003) cumulative convertible preferred stock, representing 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding, for 5.0 million shares of our common stock pursuant to a tender offer. No cash was received or paid in connection with this transaction.
- Completed public offerings of $500 million of 7.625% Senior Notes due 2013, 2.0 million shares of 6.25% mandatory convertible preferred stock having a liquidation preference of $250 per share, and 25 million shares of common stock at $29.05 per share. Net proceeds of approximately $1.666 billion were used to fund acquisitions, to repay borrowings under our revolving bank credit facility and for general corporate purposes.

Third Quarter 2006

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

Contractual Obligations

We currently have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006 and to $2.5 billion in September 2006. As of September 30, 2006, we had $1.464 billion in outstanding borrowings under this facility and had utilized $6.2 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires

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us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 1.87 to 1 at September 30, 2006. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

We also have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for these facilities is May 2010. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1.0% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of September 30, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $252.1 million under one of the facilities and an asset of $823.2 million under the other facility. As of November 3, 2006, the fair market value of the same transactions was an asset of approximately $152.2 million and $255.5 million, respectively. 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.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly-owned subsidiaries except minor subsidiaries. Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

As of September 30, 2006, our senior notes consisted of the following ($ in thousands):

7.5% Senior Notes due 2013	$ 363,823
7.625% Senior Notes due 2013	500,000
7.0% Senior Notes due 2014	300,000
7.5% Senior Notes due 2014	300,000
7.75% Senior Notes due 2015	300,408
6.375% Senior Notes due 2015	600,000
6.625% Senior Notes due 2016	600,000
6.875% Senior Notes due 2016	670,437
6.5% Senior Notes due 2017	1,100,000
6.25% Senior Notes due 2018	600,000
6.875% Senior Notes due 2020	500,000
2.75% Contingent Convertible Senior Notes due 2035	690,000
Discount on senior notes	(103,939)
Discount for interest rate derivatives	(23,621)
	$ 6,397,108

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

As of September 30, 2006 and currently, debt ratings for the senior notes are Ba2 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly-owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of September 30, 2006, we estimate that secured commercial bank indebtedness of approximately $5.4 billion could have been incurred under the most restrictive indenture covenant.

In September 2006, our wholly owned subsidiary, Nomac Drilling Corporation, sold 18 of its drilling rigs and related equipment for $187.5 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for an initial term of eight years from October 1, 2006 at rental payments of $26.0 million annually. Nomac s lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. This transaction was recorded as a sale and operating leaseback, with an aggregate deferred gain of $14.8 million on the sale which will be amortized to service operations expense over the lease term. Under the rig lease, we have the option to purchase the rigs on September 30, 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.

Commitments related to these lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2006, minimum future rig lease payments were as follows (in thousands):

2006	$ 6,130
2007	25,993
2008	25,993
2009	25,993
2010	25,993
Thereafter	97,478
Total	$ 207,580

Results of Operations Three Months Ended September 30, 2006 vs. September 30, 2005

General. For the Current Quarter, Chesapeake had net income of $548.3 million, or $1.13 per diluted common share, on total revenues of $1.929 billion. This compares to net income of $177.0 million, or $0.43 per diluted common share, on total revenues of $1.083 billion during the Prior Quarter.

Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.493 billion compared to $720.9 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 146.9 bcfe at a weighted average price of $8.54 per mcfe, compared to 120.4 bcfe produced in the Prior Quarter at a weighted average price of $6.85 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $238.5 million and ($104.0) million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $247.9 million and increased production resulted in a $181.8 million increase, for a total increase in revenues of $429.7 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Quarter to the Current Quarter is due to the combination of drilling and acquisitions completed in 2005 and 2006.

For the Current Quarter, we realized an average price per barrel of oil of $60.62, compared to $53.30 in the Prior Quarter (weighted average prices for both quarters 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 $8.39 and $6.64 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $301.4 million, or $2.05 per mcfe, in the Current Quarter and a net decrease of $122.6 million, or $1.02 per mcfe, in the Prior Quarter.

The change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $13.4 million and $12.8 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $2.2 million and $2.1 million, respectively, without considering the effect of derivative activities.

The following table shows our production by region for the Current Quarter and the Prior Quarter:

	For the Three Months Ended September 30,			
	2006		2005	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	80,946	55%	74,910	62%
South Texas and Texas Gulf Coast	19,421	13	17,018	14
Appalachian Basin	11,750	8		
Barnett Shale	11,557	8	4,898	4
Ark-La-Tex	11,529	8	10,945	9
Permian Basin	11,072	8	11,843	10
Other	615		743	1
Total Production	146,890	100%	120,357	100%

Natural gas production represented approximately 91% of our total production volume on a natural gas equivalent basis in the Current Quarter, compared to 90% in the Prior Quarter.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $398.1 million in oil and natural gas marketing sales to third parties in the Current Quarter, with corresponding oil and natural gas marketing expenses of $384.5 million, for a net margin of $13.6 million. This compares to sales of $361.9 million, expenses of $353.5 million and a net margin of $8.4 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and natural gas marketing sales volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired in the Current Period. Chesapeake recognized $38.1 million in service operations revenue in the Current Quarter with corresponding service operations expense of $18.8 million, for a net margin of $19.3 million. During the Prior Quarter, service operations for third parties were insignificant.

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Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $124.0 million in the Current Quarter compared to $80.8 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.84 per mcfe in the Current Quarter compared to $0.67 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher third-party field service costs, energy costs, ad valorem tax increases and personnel costs. We expect that production expenses for the remainder of 2006 will range from $0.85 to $0.95 per mcfe produced.

Production Taxes. Production taxes were $40.6 million and $53.1 million in the Current Quarter and the Prior Quarter, respectively. On a unit-of-production basis, production taxes were $0.28 per mcfe in the Current Quarter compared to $0.44 per mcfe in the Prior Quarter. This decrease is the result of an increase in production tax exemptions realized in addition to a decrease in natural gas prices. 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 the remainder of 2006 to range from $0.36 to $0.40 per mcfe produced based on NYMEX prices of $56.25 per barrel of oil and natural gas prices ranging from $6.40 to $7.20 per mcf.

General and Administrative Expenses. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and natural gas properties, were $37.4 million in the Current Quarter and $15.8 million in the Prior Quarter. General and administrative expenses were $0.25 and $0.13 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter 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 $8.5 million and $5.2 million for the Current Quarter and Prior Quarter, respectively. We anticipate that general and administrative expenses for the remainder of 2006 will be between $0.27 and $0.33 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.11 per mcfe).

Our stock-based compensation for employees and non-employee directors is principally in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors since July 2005. Stock-based compensation awards before 2004 (and before 2005 for non-employee directors) were in the form of stock options. Employee stock-based compensation awards 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. Under this transition method, compensation cost in 2006 includes the portion vesting in the period for (1) all share-based payments granted prior to, but not vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123 and (2) all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). Results for prior periods have not been restated.

Stock-based compensation expense increased from $5.2 million in the Prior Quarter to $8.5 million in the Current Quarter. This increase is primarily due to additional restricted stock grants to employees during the past year.

The discussion of stock-based compensation in note 1 to the financial statements included in Part I 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 exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $49.0 million and $29.5 million of internal costs in the Current Quarter and the Prior Quarter, 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 $343.7 million and $231.1 million during the Current Quarter and the Prior Quarter, 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 $2.34 and $1.92 in the Current Quarter and in the Prior Quarter, respectively. The $0.42 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2006 to be between $2.35 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $27.0 million in the Current Quarter, compared to $12.9 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of depreciation of assets acquired in 2005 and 2006. These assets include various gathering facilities and compression equipment, new buildings constructed at our corporate headquarters complex and at various field office locations, additional drilling rigs and oilfield trucks and new information technology equipment and software. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent drilling rigs are used to drill Chesapeake wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for the remainder of 2006 to be between $0.19 and $0.23 per mcfe produced.

Interest and Other Income. Interest and other income was $5.1 million in the Current Quarter compared to $2.4 million in the Prior Quarter. The Current Quarter income consisted of $1.8 million of interest income, $2.3 million related to earnings of equity investees, a $0.1 million gain on sale of assets and $0.9 million of miscellaneous income. The Prior Quarter income consisted of $0.4 million of interest income, ($0.1) million related to earnings of equity investees and $2.1 million of miscellaneous income.

Interest Expense. Interest expense increased to $74.1 million in the Current Quarter compared to $58.6 million in the Prior Quarter as follows:

	Three Months Ended September 30, 2006	2005
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 122.3	$ 77.6
Capitalized interest	(49.3)	(20.8)
Amortization of loan discount	2.0	1.4
Unrealized (gain) loss on interest rate derivatives	(2.5)	1.2
Realized (gain) loss on interest rate derivatives	1.6	(0.8)
Total interest expense	$ 74.1	$ 58.6
Average long-term borrowings	$ 6,525	$ 4,047

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

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by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears later in Item 3 Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in the Current Quarter compared to $0.48 per mcfe in the Prior Quarter. We expect interest expense for the remainder of 2006 to be between $0.58 and $0.62 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Repurchases or Exchanges of Chesapeake Debt. We repurchased or exchanged Chesapeake debt in the Prior Quarter and incurred losses in connection with the transactions. The following table shows the losses related to these transactions ($ in millions):

	Notes	**Loss on Repurchases/Exchanges**		
For the Three Months Ended September 30, 2005:	**Retired**	**Premium**	**Other(a)**	**Total**
8.125% Senior Notes due 2011	$ 7.6	$ 0.5	$ 0.1	$ 0.6
9.0% Senior Notes due 2012	1.1	0.1	0.0	0.1
	$ 8.7	$ 0.6	$ 0.1	$ 0.7

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with retired notes and transaction costs.
There were no repurchases or exchanges of Chesapeake debt in the Current Quarter.

Income Tax Expense. Chesapeake recorded income tax expense of $336.1 million in the Current Quarter, compared to income tax expense of $101.7 million in the Prior Quarter. Our effective income tax rate increased to 38% in the Current Quarter compared to 36.5% in the Prior Quarter. This increase included the impact that both state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas House Bill 3 was signed into law which eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. Although the new margin tax is not effective until 2007, the provisions of SFAS 109, *Accounting for Income Taxes*, require us to record the impact that this change has on our liability for additional deferred income taxes in the period of enactment. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Results of Operations Nine Months Ended September 30, 2006 vs. September 30, 2005

General. For the Current Period, Chesapeake had net income of $1.532 billion, or $3.40 per diluted common share, on total revenues of $5.458 billion. This compares to net income of $495.8 million, or $1.32 per diluted common share, on total revenues of $2.914 billion during the Prior Period.

Oil and Natural Gas Sales. During the Current Period, oil and natural gas sales were $4.190 billion compared to $2.032 billion in the Prior Period. In the Current Period, Chesapeake produced 426.3 bcfe at a weighted average price of $8.77 per mcfe, compared to 338.2 bcfe produced in the Prior Period at a weighted average price of $6.42 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $452.6 million and ($137.1) million in the Current Period and Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $1.003 billion and increased production resulted in a $565.5 million increase, for a total increase in revenues of $1.568 billion (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Period to the Current Period is due to the combination of drilling as well as acquisitions completed in 2005 and the Current Period.

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For the Current Period, we realized an average price per barrel of oil of $58.86 compared to $46.04 in the Prior Period (weighted average prices for both periods 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 $8.66 and $6.27 in the Current Period and Prior Period, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $807.1 million, or $1.89 per mcfe, in the Current Period and a net decrease of $126.6 million, or $0.37 per mcfe, in the Prior Period.

The change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $38.8 million and $36.9 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $6.4 million and $6.1 million, respectively, without considering the effect of derivative activities.

The following table shows our production by region for the Current Period and the Prior Period:

	For the Nine Months Ended September 30,			
	2006		2005	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	233,078	55%	222,290	65%
South Texas and Texas Gulf Coast	59,040	14	45,082	13
Permian Basin	34,582	8	28,955	9
Ark-La-Tex	34,410	8	28,845	9
Appalachian Basin	33,268	8		
Barnett Shale	30,035	7	10,927	3
Other	1,905		2,065	1
Total Production	426,318	100%	338,164	100%

Natural gas production represented approximately 91% of our total production volume on a natural gas equivalent basis in the Current Period, compared to 90% in the Prior Period.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $1.170 billion in oil and natural gas marketing sales to third parties in the Current Period, with corresponding oil and natural gas marketing expenses of $1.132 billion, for a net margin of $38.6 million. This compares to sales of $882.0 million, expenses of $860.8 million and a net margin of $21.2 million in the Prior Period. In the Current Period, Chesapeake realized an increase in oil and natural gas marketing sales volumes and an increase in oil and natural gas prices.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired in the Current Period. Chesapeake recognized $97.5 million in service operations revenue in the Current Period with corresponding service operations expenses of $48.9 million, for a net margin of $48.6 million principally associated with businesses acquired in the Current Period. During the Prior Period, service operations for third parties were insignificant.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $364.1 million in the Current Period compared to $222.7 million in the Prior Period. On a unit-of-production basis, production expenses were $0.85 per mcfe in the Current Period compared to $0.66 per mcfe in the Prior Period. The increase in the Current Period was primarily due to higher third-party field service costs, energy costs, ad valorem tax increases and personnel costs. We expect that production expenses for the remainder of 2006 will range from $0.85 to $0.95 per mcfe produced.

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Production Taxes. Production taxes were $129.9 million and $136.3 million in the Current Period and the Prior Period, respectively. On a unit-of-production basis, production taxes were $0.30 per mcfe in the Current

Period compared to $0.40 per mcfe in the Prior Period. The Current Period included a $2.1 million accrual for certain severance tax claims and then a subsequent reversal of the cumulative $11.6 million accrual for such severance tax claims as a result of their dismissal. The Prior Period included an accrual of $5.0 million associated with such severance tax claims. Excluding these items, production taxes were $0.33 per mcfe in the Current Period and $0.39 per mcfe in the Prior Period. This decrease is the result of an increase in production tax exemptions realized. 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 the remainder of 2006 to range from $0.36 to $0.40 per mcfe produced based on NYMEX prices of $56.25 per barrel of oil and natural gas prices ranging from $6.40 to $7.20 per mcf.

General and Administrative Expenses. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and natural gas properties, were $99.7 million in the Current Period and $39.6 million in the Prior Period. General and administrative expenses were $0.23 and $0.12 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period 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 $21.3 million and $10.2 million for the Current Period and Prior Period, respectively. We anticipate that general and administrative expenses for the remainder of 2006 will be between $0.27 and $0.33 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.11 per mcfe).

Our stock-based compensation for employees and non-employee directors is principally in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors annually since July 2005. Employee compensation awards before 2004 (and before 2005 for non-employee directors) were in the form of stock options. These stock-based compensation awards 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. Under this transition method, compensation cost in 2006 includes the portion vesting in the period for (1) all share-based payments granted prior to, but not vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123 and (2) all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). Results for prior periods have not been restated.

Stock-based compensation expense increased from $10.2 million in the Prior Period to $21.3 million in the Current Period. Of this increase, $1.9 million was due to stock option expense, $9.1 million was due to a higher number of unvested restricted shares outstanding during the Current Period compared to the Prior Period and $0.1 million was due to stock granted to a new director.

The discussion of stock-based compensation in note 1 to the financial statements included in Part I 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 exploration and development activities and do not include any costs related to

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production, general corporate overhead or similar activities. We capitalized $119.3 million and $75.3 million of internal costs in the Current Period and the Prior Period, 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 $976.8 million and $621.5 million during the Current Period and the Prior Period, 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 $2.29 and $1.84 in the Current Period and in the Prior Period, respectively. The $0.45 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2006 to be between $2.35 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $74.1 million in the Current Period, compared to $34.8 million in the Prior Period. The increase in the Current Period was primarily the result of the depreciation of recently acquired assets resulting from our acquisition of various gathering facilities and compression equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations, the purchase of additional drilling rigs and oilfield trucks and the purchase of additional information technology equipment and software. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for the remainder of 2006 to be between $0.19 and $0.23 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 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, we incurred an expense of $54.8 million in the Current Period.

Interest and Other Income. Interest and other income was $19.7 million in the Current Period compared to $7.8 million in the Prior Period. The Current Period income consisted of $3.1 million of interest income, $9.5 million related to earnings of equity investees, a $3.5 million gain on sale of assets and $3.6 million of miscellaneous income. The Prior Period income consisted of $3.5 million of interest income, $1.1 million related to earnings of equity investees and $3.2 million of miscellaneous income.

Interest Expense. Interest expense increased to $220.2 million in the Current Period compared to $155.6 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2006	**2005**
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 335.8	$ 210.7
Capitalized interest	(119.2)	(54.8)
Amortization of loan discount	5.3	4.2
Unrealized (gain) loss on interest rate derivatives	(0.8)	(1.9)
Realized (gain) loss on interest rate derivatives	(0.9)	(2.6)
Total interest expense	$ 220.2	$ 155.6
Average long-term borrowings	$ 6,125	$ 3,593

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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. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears later in Item 3 Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in the Current Period compared to $0.47 per mcfe in the Prior Period. We expect interest expense for the remainder of 2006 to be between $0.58 and $0.62 per mcfe produced (before considering the effect of interest rate derivatives).

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

Loss on Repurchases or Exchanges of Chesapeake Senior Notes. We repurchased or exchanged Chesapeake debt in the Prior Period and incurred losses in connection with the transactions. The following table shows the losses related to these transactions ($ in millions):

	Notes	**Loss on Repurchases/Exchanges**		
For the Nine Months Ended September 30, 2005:	**Retired**	**Premium**	**Other(a)**	**Total**
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 556.4	$ 59.5	$ 10.5	$ 70.0

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

There were no repurchases or exchanges of Chesapeake debt in the Current Period.

Income Tax Expense. Chesapeake recorded income tax expense of $963.1 million in the Current Period, compared to income tax expense of $285.0 million in the Prior Period. Our effective income tax rate increased to 38.6% in the Current Period compared to 36.5% in the Prior Period. This increase included the impact that both state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas House Bill 3 was signed into law which eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. Although the new margin tax is not effective until 2007, the provisions of SFAS 109, *Accounting for Income Taxes*, require us to record the impact that this change has on our liability for deferred income taxes in the period of enactment. As a result, we recorded $15 million in additional deferred state income tax expense, net of the federal income tax benefit, in the Current Period. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Current Period. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2005.

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Recently Issued Accounting Standards

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

In December 2004, the FASB issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

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

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

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

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact SFAS 157 will have on our financial position, results of operations or cash flows.

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

Forward-Looking Statements

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

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005 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,
- lower oil and natural gas prices negatively affecting our ability to borrow, and
- drilling and operating risks.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this 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 3. ***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 September 30, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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

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

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

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

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

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

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

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

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or natural gas from a specified delivery point. We currently have basis protection swaps covering six different delivery points, four in the Mid-Continent and two in the Appalachian Basin, which correspond to the actual prices we receive for much of our natural gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future natural gas price differentials. As of September 30, 2006, the fair value of our basis protection swaps was $178.8 million. As of September 30, 2006, our Mid-Continent basis protection swaps covered approximately 29% of our anticipated Mid-Continent natural gas production remaining in 2006, 25% in 2007, 18% in 2008 and 13% in 2009. As of September 30, 2006, our Appalachian Basin basis protection swaps cover approximately 74% of our anticipated Appalachian Basin natural gas production in 2007, 65% in 2008 and 30% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $301.4 million, ($122.6) million, $807.1 million and ($126.6) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $238.5 million, ($104.0) million, $452.6 million and ($137.1) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $171.8 million, ($99.5) million, $336.7 million and ($98.9) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

As of September 30, 2006, we had the following open oil and natural gas derivative instruments (excluding CNR derivatives assumed) designed to hedge a portion of our oil and natural gas production for periods after September 2006:

	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 Received ($ in thousands)	Fair Value at September 30, 2006 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
4Q 2006	106,585,000	$ 9.68	$	$	$	Yes	$	$ 422,505
1Q 2007	102,150,000	11.09				Yes		336,329
2Q 2007	78,715,000	9.18				Yes		152,602
3Q 2007	79,580,000	9.24				Yes		142,030
4Q 2007	79,580,000	9.90				Yes		135,751
1Q 2008	64,610,000	10.84				Yes		114,992
2Q 2008	64,610,000	8.45				Yes		71,924
3Q 2008	65,320,000	8.51				Yes		67,639
4Q 2008	65,320,000	9.15				Yes		68,693
1Q 2009	900,000	10.53				Yes		1,551
2Q 2009	910,000	8.29				Yes		1,093
3Q 2009	920,000	8.34				Yes		1,026
4Q 2009	920,000	8.95				Yes		998
Basis Protection Swaps (Mid-Continent):								
4Q 2006	33,720,000				(0.32)	No		13,446
1Q 2007	32,850,000				(0.29)	No		18,781
2Q 2007	34,125,000				(0.35)	No		13,449
3Q 2007	34,500,000				(0.35)	No		11,385
4Q 2007	35,720,000				(0.32)	No		25,796
1Q 2008	33,215,000				(0.30)	No		28,210
2Q 2008	26,845,000				(0.25)	No		15,241
3Q 2008	27,140,000				(0.25)	No		13,469
4Q 2008	31,410,000				(0.28)	No		18,293
1Q 2009	26,100,000				(0.32)	No		13,746

2Q 2009	20,020,000	(0.28)	No	1,906
3Q 2009	20,240,000	(0.28)	No	1,348
4Q 2009	20,240,000	(0.28)	No	4,726

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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 Received ($ in thousands)	Fair Value at September 30, 2006 ($ in thousands)
Basis Protection Swaps (Appalachian Basin):								
1Q 2007	9,000,000	$	$	$	$ 0.35	No	$	$ 273
2Q 2007	9,100,000				0.35	No		(462)
3Q 2007	9,200,000				0.35	No		(491)
4Q 2007	9,200,000				0.35	No		(55)
1Q 2008	9,100,000				0.35	No		652
2Q 2008	9,100,000				0.35	No		(338)
3Q 2008	9,200,000				0.35	No		(365)
4Q 2008	9,200,000				0.35	No		(152)
1Q 2009	4,500,000				0.31	No		205
2Q 2009	4,550,000				0.31	No		(108)
3Q 2009	4,600,000				0.31	No		(121)
4Q 2009	4,600,000				0.31	No		(2)
Cap-Swaps:								
4Q 2006	11,960,000	6.89	5.13			No		(1,869)
1Q 2007	14,400,000	11.44	5.73			No		28,620
2Q 2007	19,110,000	9.57	5.91			No		8,120
3Q 2007	19,320,000	9.76	5.91			No		2,402
4Q 2007	19,320,000	10.56	5.91			No		6,113
1Q 2008	19,110,000	11.58	6.18			No		11,135
2Q 2008	19,110,000	10.00	6.18			No		6,369
3Q 2008	19,320,000	10.09	6.18			No		3,863
4Q 2008	19,320,000	10.65	6.18			No		4,383
Counter Swaps:								
4Q 2006	(36,605,000)	5.27				No		600
1Q 2007	(900,000)	7.53				No		243
2Q 2007	(4,550,000)	7.09				No		675
3Q 2007	(4,600,000)	7.31				No		659
4Q 2007	(4,600,000)	8.03				No		755
1Q 2008	(4,550,000)	8.84				No		1,000
2Q 2008	(4,550,000)	7.14				No		880
3Q 2008	(4,600,000)	7.28				No		903
4Q 2008	(4,600,000)	7.90				No		931
Call Options:								
4Q 2006	1,840,000			12.50		No	1,932	(51)
1Q 2007	6,300,000			11.58		No	1,890	(2,575)
2Q 2007	6,370,000			9.96		No	1,911	(3,077)
3Q 2007	6,440,000			10.04		No	1,932	(4,835)
4Q 2007	6,440,000			10.56		No	1,932	(6,590)
1Q 2008	1,820,000			12.50		No	1,911	(1,997)
2Q 2008	1,820,000			12.50		No	1,911	(545)
3Q 2008	1,840,000			12.50		No	1,932	(773)
4Q 2008	1,840,000			12.50		No	1,932	(1,373)
Locked Swaps:								
4Q 2006	6,440,000					No		(4,706)
1Q 2007	6,300,000					No		(4,789)
2Q 2007	6,370,000					No		(2,517)
3Q 2007	6,440,000					No		(2,049)
4Q 2007	6,440,000					No		(2,272)
Total Natural Gas							17,283	1,733,598

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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 Received ($ in thousands)	Fair Value at September 30, 2006 ($ in thousands)
Oil (bbls):								
Swaps:								
4Q 2006	1,656,000	$ 65.38	$	$	$	Yes	$	$ 2,275
1Q 2007	1,350,000	67.98				Yes		2,356
2Q 2007	1,092,000	70.04				Yes		2,747
3Q 2007	1,104,000	69.71				Yes		1,556
4Q 2007	1,104,000	69.31				Yes		697
1Q 2008	1,001,000	70.44				Yes		1,491
2Q 2008	1,001,000	70.02				Yes		1,161
3Q 2008	1,012,000	69.60				Yes		968
4Q 2008	920,000	68.79				Yes		476
1Q 2009	45,000	66.64				Yes		(50)
2Q 2009	45,500	66.27				Yes		(47)
3Q 2009	46,000	65.92				Yes		(43)
4Q 2009	46,000	65.56				Yes		(40)
Cap-Swaps:								
4Q 2006	184,000	68.02	50.00			No		633
1Q 2007	360,000	78.53	56.25			No		3,805
2Q 2007	364,000	78.53	56.25			No		3,161
3Q 2007	368,000	78.53	56.25			No		2,736
4Q 2007	368,000	78.53	56.25			No		2,444
1Q 2008	273,000	77.60	55.00			No		1,487
2Q 2008	273,000	77.60	55.00			No		1,396
3Q 2008	276,000	77.60	55.00			No		1,348
4Q 2008	276,000	77.60	55.00			No		1,307
Total Oil								31,864
Total Natural Gas and Oil							$ 17,283	$ 1,765,462

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 September 30, 2006.

Based upon the market prices at September 30, 2006, we expect to transfer approximately $530.2 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 September 30, 2006 are expected to mature by December 31, 2009.

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

	2006 ($ in thousands)
Fair value of contracts outstanding, as of January 1	$ (945,814)
Change in fair value of contracts during the period	3,261,182
Fair value of contracts when entered into during the period	(32,300)
Contracts realized or otherwise settled during the period	(807,074)
Fair value of contracts outstanding, as of September 30	$ 1,475,994

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The change in the fair value of our derivative instruments since January 1, 2006 resulted from the settlement of derivatives for a realized gain, as well as a decrease in natural gas prices. Derivative instruments reflected as current in the condensed 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 condensed consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

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

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

The following details the assumed CNR derivatives remaining as of September 30, 2006:

	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 September 30, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
4Q 2006	10,626,000	$ 4.86	$	$	Yes	$ (9,313)
1Q 2007	10,350,000	4.82			Yes	(30,297)
2Q 2007	10,465,000	4.82			Yes	(24,548)
3Q 2007	10,580,000	4.82			Yes	(26,672)
4Q 2007	10,580,000	4.82			Yes	(33,722)
1Q 2008	9,555,000	4.68			Yes	(39,074)
2Q 2008	9,555,000	4.68			Yes	(23,387)
3Q 2008	9,660,000	4.68			Yes	(24,581)
4Q 2008	9,660,000	4.66			Yes	(29,997)
1Q 2009	4,500,000	5.18			Yes	(14,498)
2Q 2009	4,550,000	5.18			Yes	(7,627)
3Q 2009	4,600,000	5.18			Yes	(8,162)
4Q 2009	4,600,000	5.18			Yes	(10,574)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(2,538)
2Q 2009	910,000		4.50	6.00	Yes	(1,268)
3Q 2009	920,000		4.50	6.00	Yes	(1,375)
4Q 2009	920,000		4.50	6.00	Yes	(1,835)
Total Natural Gas						$ (289,468)

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Subsequent to September 30, 2006, Chesapeake lifted a portion of its fourth quarter 2006 and full-year 2007, 2008 and 2009 hedges and as a result received $407 million in cash from its hedging counterparties. The gain will be recorded in accumulated other comprehensive income and in unrealized oil and natural gas sales based on the designation of the hedges. The gain will be recognized in realized oil and natural gas sales in the month of the hedged production.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of September 30, 2006, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	2006	2007	2008	2009	2010	Years of Maturity Thereafter ($ in billions)	Total	Fair Value
Liabilities:								
Long-term debt fixed-rate (a)	$	$	$	$	$	$ 6.525	$ 6.525	$ 6.317
Average interest rate						6.4%	6.4%	6.4%
Long-term debt variable rate	$	$	$	$	$	$ 1.464	$ 1.464	$ 1.464
Average interest rate						6.5%	6.5%	6.5%

(a) This amount does not include the discount included in long-term debt of ($103.9) million and the discount for interest rate swaps of ($23.6) 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 condensed 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 certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.6) million, $0.8 million, $0.9 million and $2.6 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, 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 condensed consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $2.5 million, ($1.2) million, $0.8 million and $1.9 million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

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As of September 30, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,919)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(6,301)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,456)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(7,305)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(3,308)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(7,124)
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points	(3,178)
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points	(172)
				$ (36,763)

In the Current Period, we closed three interest rate swaps for gains totaling $3.0 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

To mitigate our short-term exposure to rising interest rates on a portion of our long-term debt that has been converted to floating-rate, we have entered into zero-cost collar transactions. These collars contain a fixed floor rate (put) and fixed ceiling rate (call). If LIBOR exceeds the ceiling rate or falls below the floor rate, Chesapeake pays the fixed rate and receives LIBOR. If LIBOR is between the ceiling and floor rates, no payments are due from either party. As of September 30, 2006, we were a party to the following zero-cost interest rate collars:

Payment Dates	Notional Amount	LIBOR Floor	LIBOR Ceiling
July 2007 January 2010	$150,000,000	4.53%	5.37%
June 2007 December 2009	$150,000,000	4.53%	5.37%
August 2007 February 2010	$250,000,000	4.53%	5.37%
July 2007 January 2010	$250,000,000	4.53%	5.37%

ITEM 4. *Controls and Procedures*

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

No changes in Chesapeake s internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, Chesapeake s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

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

Item 1A. ***Risk Factors***

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

On September 29, 2006, we issued 1,375,989 shares of our common stock to Altoma Energy, an Oklahoma general partnership, in exchange for 40,000 shares of common stock of Chaparral Energy, Inc. The Chesapeake shares were valued at $40 million, based on the average closing price during a ten trading-day period beginning September 13, 2006, and were issued in a private offering without registration under the Securities Act of 1933 in reliance on the exemption provided in Section 4(2) of such Act.

The following table presents information about repurchases of our common stock during the three months ended September 30, 2006:

Period	Total Number of Shares Purchased(a)	Average Price Paid Per Share(a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs(b)
July 1, 2006 through July 31, 2006	163,509	$ 29.916		
August 1, 2006 through August 31, 2006	14,645	32.411		
September 1, 2006 through September 30, 2006	2,338	28.980		
Total	180,492	$ 30.106		

(a) Includes 32 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the company of 9,587 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 170,873 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 company contributions.

Item 3. ***Defaults Upon Senior Securities***

Not applicable.

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

Not applicable.

Item 5. ***Other Information***

Not applicable.

Item 6. ***Exhibits***

The following exhibits are filed as a part of this report:

Exhibit Number	Description
3.1.1	Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended. Incorporated herein by reference to Exhibit 3.1.3 Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.4	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.4 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed November 9, 2005.
3.1.6	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake s Form 10-Q for the quarter ended March 31, 2005.
3.1.7	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed September 15, 2005.
3.2	Bylaws, as amended and restated. Incorporated herein by reference to Exhibit 3.2 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003.
4.1.1*	Eighth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2.1*	Eighth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3.1*	Twelfth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.75% senior notes due 2015.

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Exhibit Number	Description
4.5.1*	Commitment Increase Agreement dated September 1, 2006, by and among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as administrative agent and the several lenders party thereto.
4.6.1*	Eleventh Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.
4.7.1*	Ninth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.
4.8.1*	Seventh Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.
4.9.1*	Fifth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.
4.10.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
4.11.1*	Fifth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.
4.12.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.
4.13.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.
4.14.1*	First Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.625% senior notes due 2013.
10.1.1 *	Chesapeake s 2003 Stock Incentive Plan, as amended.
10.1.3 *	Chesapeake s 1994 Stock Option Plan, as amended.
10.1.4 *	Chesapeake s 1996 Stock Option Plan, as amended.
10.1.5 *	Chesapeake s 1999 Stock Option Plan, as amended.

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Exhibit Number	Description
10.1.6 *	Chesapeake s 2000 Employee Stock Option Plan, as amended.
10.1.8 *	Chesapeake s 2001 Stock Option Plan, as amended.
10.1.10 *	Chesapeake s 2001 Nonqualified Stock Option Plan, as amended.
10.1.11 *	Chesapeake s 2002 Stock Option Plan, as amended.
10.1.13 *	Chesapeake s 2002 Nonqualified Stock Option Plan, as amended.
10.2.2	Employment Agreement dated as of October 1, 2006 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.3	Employment Agreement dated as of October 1, 2006 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.4	Employment Agreement dated as of October 1, 2006 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.5	Employment Agreement dated as of October 1, 2006 between Douglas J. Jacobson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.5 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.6	Employment Agreement dated as of October 1, 2006 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.6 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.7	Employment Agreement dated as of October 1, 2006 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.8	Employment Agreement dated as of October 1, 2006 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake s current report on Form 8-K filed October 5, 2006.
12*	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
31.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.
Management contract or compensatory plan or arrangement

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SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE ENERGY CORPORATION
(Registrant)

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon

Chairman of the Board and

Chief Executive Officer

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland

Executive Vice President and

Chief Financial Officer

Date: November 7, 2006

INDEX TO EXHIBITS

Exhibit Number	Description
3.1.1	Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended. Incorporated herein by reference to Exhibit 3.1.3 Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.4	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.4 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed November 9, 2005.
3.1.6	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake s Form 10-Q for the quarter ended March 31, 2005.
3.1.7	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed September 15, 2005.
3.2	Bylaws, as amended and restated. Incorporated herein by reference to Exhibit 3.2 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003.
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600,000,000

Chesapeake Energy Corporation

$6\,^1/_4$% Senior Notes due 2017

PROSPECTUS

December 1, 2006

Joint Book-Running Managers

Barclays Capital

Credit Suisse

Deutsche Bank Securities

Goldman Sachs International

Senior Co-Managers

ABN AMRO

Banc of America Securities Limited

BNP PARIBAS

Fortis Securities

Lehman Brothers

The Royal Bank of Scotland plc

UBS Investment Bank

Co-Managers

Bayerische Hypo- und Vereinsbank AG

BMO Capital Markets

Calyon Securities (USA)

DZ Financial Markets LLC

Natexis Bleichroeder Inc.

RBC Capital Markets

TD Securities