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, 2001

[ ] 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
7.875% Senior Notes due 2004	New York Stock Exchange
8.375% Senior Notes due 2008	New York Stock Exchange
8.125% Senior Notes due 2011	New York Stock Exchange
8.5% Senior Notes due 2012	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
NONE

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. [ ]

The aggregate market value of Common Stock held by non-affiliates on March 22, 2002 was $1,039,974,948. At such date, there were 165,773,281 shares of Common Stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

PORTIONS OF THE REGISTRANT'S DEFINITIVE PROXY STATEMENT FOR THE 2002 ANNUAL MEETING OF SHAREHOLDERS ARE INCORPORATED BY REFERENCE IN PART III

PART I

ITEM 1. BUSINESS

GENERAL

We are one of the ten largest independent natural gas producers in the United States. Chesapeake began operations in 1989 and completed its initial public offering in 1993. Our common stock trades on the New York Stock Exchange under the symbol CHK. 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. Chesapeake maintains a website at www.chkenergy.com. Information contained on our website is not part of this report.

At the end of 2001, we owned interests in approximately 8,700 producing oil and gas wells. Our primary operating area is the Mid-Continent region of the United States, which includes Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle. Other operating areas include the Deep Giddings field in Texas, a portion of the Permian Basin region of southeastern New Mexico and a portion of the Williston Basin located in eastern Montana and western North Dakota. The following table highlights our growth since 1996:

	YEARS ENDED DECEMBER 31,						FIVE-YEAR COMPOUND ANNUAL GROWTH RATE
	1996	1997	1998	1999	2000	2001	
Production (mmcfe)	69,867	80,302	130,277	133,492	134,179	161,451	18%
Proved reserves (mmcfe)	494,000	448,474	1,091,348	1,205,595	1,354,813	1,779,946	29%
EBITDA ($ in 000's)	$144,340	$ 256,421	$ 183,449	$ 218,936	$ 391,190	$ 619,933	34%
Operating cash flow ($ in 000's) ..	$130,989	$ 226,639	$ 115,200	$ 137,884	$ 304,934	$ 521,612	32%
Net income (loss) ($ in 000's)	$ 39,902	$(233,429)	$ (933,854)	$ 33,266	$ 455,570	$ 217,406	40%

BUSINESS STRATEGY

From inception in 1989, our business strategy has been to aggressively build and develop one of the largest onshore natural gas resource bases in the United States. We are executing our strategy by:

- continuing to grow through the drillbit by conducting what we believe is currently one of the most active drilling programs in the United States. We currently have 15 rigs drilling on Chesapeake-operated prospects and we are participating in 19 wells being drilled by others;

- continuing to make small to medium-sized acquisitions of strategically located natural gas properties that provide high quality production and significant drilling opportunities. In 2001, we invested approximately $706 million to acquire 648 bcfe in 160 separate transactions. In our experience, small to medium-sized acquisitions generally provide better economics than large corporate acquisitions;

- maintaining a low operating cost structure so that we can deliver attractive financial returns from our assets in all phases of the commodity price cycle; and

- reducing our exposure to volatile oil and natural gas markets and increasing our return on capital by periodically hedging projected future period oil and natural gas production.

Based on our view that natural gas has become the fuel of choice to meet growing power demand and increasing environmental concerns, we believe our strategy should provide substantial growth opportunities in the years ahead.

COMPANY STRENGTHS

We believe our past performance and future growth potential are primarily attributable to five characteristics that distinguish us from other independent oil and natural gas producers:

High-Quality Asset Base. Our properties are characterized by long-lived reserves, established production profiles and an emphasis on natural gas. Based upon 2001 production and our year-end reserves, our proved reserves-to-production ratio, or reserve life, is more than eleven years. In our primary operating area of the Mid-Continent, and in our three secondary 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 concentrating our acquisition and drilling efforts in the Mid-Continent region, where approximately 84% of our proved reserves are located.

Low-Cost Producer. Our high-quality asset base has enabled us to achieve a low operating cost structure. During 2001, our cash operating costs per unit of production, which consist of general and administrative expenses and production expenses and taxes, were $0.76 per mcfe. We believe this is one of the lowest operating cost structures among publicly traded independent oil and natural gas producers. We operate approximately 81% of our proved reserves, providing a high degree of operating flexibility and cost control.

Successful Acquisition Program. Our acquisition program is focused primarily in the Mid-Continent region. This region is characterized by long-lived natural gas reserves, low lifting costs, multiple geological targets that provide substantial drilling potential, favorable basis differentials to benchmark commodity prices, a well-developed oil and gas transportation infrastructure and considerable potential for further consolidation of assets. Beginning in 1998 and continuing throughout 2001, we have successfully completed $1.6 billion in acquisitions at an average cost of approximately $1.00 per mcfe. We believe we are well positioned to continue this consolidation as a result of our large existing asset base, our corporate presence in Oklahoma City and our knowledge and expertise in the Mid-Continent.

Large Inventory of Drilling Projects. During the past 13 years, we believe we have been one of the most active drillers in the United States, especially of deep vertical and horizontal wells in challenging reservoir conditions. As a result of our land acquisition strategy, we have developed an onshore leasehold position of approximately 1.7 million net acres. In addition, our technical teams have identified over 1,500 exploratory and developmental drillsites, representing more than five years of future drilling opportunities at our current rate of drilling.

Entrepreneurial Management. Our management team formed Chesapeake in 1989 with an initial capitalization of $50,000. Through the following years, our management team has guided the company through operational challenges and extremes of oil and gas prices to create one of the ten largest independent natural gas producers in the United States with an enterprise value of $2.7 billion at March 22, 2002, consisting of $1.2 billion in fair market value related to our fully diluted common stock, $1.3 billion related to our outstanding senior notes and $150 million related to our outstanding preferred stock. In addition, our management and directors, through their ownership of approximately 19.9 million shares of our common stock, have a strong interest in increasing shareholder value.

2001 HIGHLIGHTS

Chesapeake's operating results for the year ended December 31, 2001 established several records for our company:

- income before income taxes and extraordinary item was $438 million, compared to $196 million in 2000,

- operating cash flow increased to $522 million from $305 million in 2000,

- production of oil and natural gas grew to 161 bcfe, of which 89% was natural gas, compared to 134 bcfe in 2000, and

- proved oil and gas reserves were 1,780 bcfe, an increase of 31% from the year ended December 31, 2000.

During 2001, we also replaced 892 bcfe of proved reserves (excluding downward revisions to proved reserves of 156 bcfe due to price decreases during the year and the sale of our Canadian subsidiary) at a replacement cost of $1.27 per mcfe.

2002 OUTLOOK

At the present time, we believe the outlook for Chesapeake is favorable because of our large base of high quality natural gas properties, our geological and operational expertise and a very strong portfolio of natural gas and oil hedges in place. Our goals and the strategy to obtain those goals remain unchanged for 2002:

- replace production by more than 200% at the lowest possible reserve replacement cost,
- execute a capital expenditure plan balanced between drilling and acquisitions, funded with operating cash flow,
- maintain a superior operating cost structure,
- reduce our net debt per mcfe, and
- deliver attractive financial returns from our assets in all phases of our energy cycle.

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.

	YEARS ENDED DECEMBER 31,					
	1999		2000		2001	
	GROSS	NET	GROSS	NET	GROSS	NET
United States						
Development:						
Productive	167	93.3	291	142.7	406	190.9
Non-productive	17	10.6	12	5.3	53	18.2
Total	184	103.9	303	148.0	459	209.1
Exploratory:						
Productive	9	3.7	32	17.0	28	15.4
Non-productive	6	4.6	11	5.4	25	12.0
Total	15	8.3	43	22.4	53	27.4
Canada						
Development:						
Productive	11	7.3	12	6.1	17	7.6
Non-productive	1	0.2	2	0.8	1	0.4
Total	12	7.5	14	6.9	18	8.0

At December 31, 2001, we had 25 (9.2 net) wells in process.

WELL DATA

At December 31, 2001, we had interests in approximately 8,700 (3,600 net) producing wells, including properties in which we held an overriding royalty interest, of which 300 (150 net) were classified as primarily oil producing wells and 8,400 (3,450 net) were classified as primarily gas producing wells. Chesapeake operates approximately 4,000 of the total 8,700 producing wells. We operate approximately 81% of our proved reserves.

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:

	YEARS ENDED DECEMBER 31,								
	1999			2000			2001		
	U.S.	CANADA	COMBINED	U.S.	CANADA	COMBINED	U.S.	CANADA	COMBINED
NET PRODUCTION:									
Oil (mbbl)	4,147	--	4,147	3,068	--	3,068	2,880	--	2,880
Gas (mmcf)	96,873	11,737	108,610	103,694	12,077	115,771	135,096	9,075	144,171
Gas equivalent (mmcfe)	121,755	11,737	133,492	122,102	12,077	134,179	152,376	9,075	161,451
OIL AND GAS SALES ($ IN THOUSANDS):									
Oil	$ 66,413	$ --	$ 66,413	$ 80,953	$ --	$ 80,953	$ 77,522	$ --	$ 77,522
Gas	200,055	13,977	214,032	355,391	33,826	389,217	626,079	31,928	658,007
Total oil and gas sales	$266,468	$ 13,977	$280,445	$436,344	$ 33,826	$470,170	$703,601	$ 31,928	$735,529
AVERAGE SALES PRICE:									
Oil ($ per bbl)	$ 16.01	$ --	$ 16.01	$ 26.39	$ --	$ 26.39	$ 26.92	$ --	$ 26.92
Gas ($ per mcf)	$ 2.07	$ 1.19	$ 1.97	$ 3.43	$ 2.80	$ 3.36	$ 4.63	$ 3.52	$ 4.56
Gas equivalent ($ per mcfe)	$ 2.19	$ 1.19	$ 2.10	$ 3.57	$ 2.80	$ 3.50	$ 4.62	$ 3.52	$ 4.56
EXPENSES ($ PER mcfe):									
Production expenses	$ 0.36	$ 0.18	$ 0.35	$ 0.38	$ 0.32	$ 0.37	$ 0.48	$ 0.26	$ 0.47
Production taxes	$ 0.11	$ --	$ 0.10	$ 0.20	$ --	$ 0.19	$ 0.22	$ --	$ 0.20
General and administrative	$ 0.10	$ 0.08	$ 0.10	$ 0.09	$ 0.17	$ 0.10	$ 0.09	$ 0.11	$ 0.09
Depreciation, depletion and amortization	$ 0.73	$ 0.52	$ 0.71	$ 0.76	$ 0.71	$ 0.75	$ 1.08	$ 0.90	$ 1.07

Our hedging activities resulted in an increase in oil and gas revenues of $105.4 million in 2001 as compared to a decrease of $30.6 million in 2000 and a decrease of $1.7 million in 1999.

In October 2001, we sold our Canadian subsidiary for approximately $143.0 million.

PROVED RESERVES

The following table sets forth our estimated proved reserves and the present value of the proved reserves (based on our weighted average wellhead prices at December 31, 2001 of $18.82 per barrel of oil and $2.51 per mcf of gas). These prices were based on the cash spot prices for oil and natural gas at December 31, 2001.

	OIL (mbbl)	GAS (mmcf)	GAS EQUIVALENT (mmcfe)	PERCENT OF PROVED RESERVES	PRESENT VALUE ($ IN THOUSANDS)
Mid-Continent	17,630	1,395,699	1,501,478	84%	$1,373,012
Gulf Coast	3,199	123,521	142,717	8%	155,430
Permian Basin	5,042	64,096	94,351	5%	88,025
Williston Basin	4,216	4,460	29,756	2%	27,814
Other areas	6	11,610	11,644	1%	2,386
Total	30,093	1,599,386	1,779,946	100%	$1,646,667

As of December 31, 2001, the present value of our proved developed reserves as a percentage of total proved reserves was 80%, and the volume of our proved developed reserves as a percentage of total proved reserves was 71%. Natural gas reserves accounted for 90% of total proved reserves at December 31, 2001.

Actual 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, 2001 present value of proved reserves of approximately $82 million and $16 million, respectively.

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:

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
	($ IN THOUSANDS)		
Development and leasehold costs ...	$ 124,118	$ 151,844	$ 350,773
Exploration costs	23,693	24,658	47,945
Acquisition costs:			
Proved properties	52,093	75,285	705,510
Unproved properties	2,747	3,625	35,132
Sales of oil and gas properties ...	(45,635)	(1,529)	(151,444)
Capitalized internal costs	2,710	6,958	8,255
Total	$ 159,726	$ 260,841	$ 996,171

ACREAGE

The following table sets forth as of December 31, 2001 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 are stated in thousands and do not include our options to acquire additional leasehold which had not been exercised.

	DEVELOPED		UNDEVELOPED		TOTAL DEVELOPED AND UNDEVELOPED	
	GROSS	NET	GROSS	NET	GROSS	NET
Mid-Continent.....	2,087,422	1,015,821	550,649	292,911	2,638,071	1,308,732
Gulf Coast........	241,301	145,017	163,438	138,782	404,739	283,799
Permian Basin	45,323	33,142	45,862	31,281	91,185	64,423
Williston Basin...	42,763	14,636	86,557	50,351	129,320	64,987
Other areas.......	16,318	9,465	4,789	3,094	21,107	12,559
Total.....	2,433,127	1,218,081	851,295	516,419	3,284,422	1,734,500

MARKETING

Chesapeake's oil production is sold under market sensitive or spot price contracts. Our natural gas production is sold to purchasers under percentage-of-proceeds and percentage-of-index contracts or by direct marketing to end users or aggregators. 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 gathering and processing 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 natural gas sales. Under percentage-of-index contracts, the price per mmbtu we receive for our gas at the wellhead is tied to indexes published in Inside FERC or Gas Daily. During 2001, sales to Continental Natural Gas, Reliant Energy Field Services, and Aquila Southwest Pipeline Corporation of $102.3 million, $87.6 million, and $71.9 million, respectively, accounted for 36% of our total oil and gas sales. Management believes that the loss of one of these customers 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 oil and gas sales in 2001.

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

HEDGING ACTIVITIES

We utilize hedging strategies to hedge the price of a portion of our future oil and natural gas production and from time to time to manage fixed interest rate exposure. See Item 7A -- Quantitative and Qualitative Disclosures About Market Risk.

RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

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

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and gas properties depend primarily upon the prices we receive for our oil and gas. 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 semi-annual redeterminations based on prices specified by our bank group at the time of redetermination. In addition, we may have ceiling test writedowns in the future if prices fall significantly below the prices at December 31, 2001.

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,
- risks associated with owning and operating drilling rigs,
- the availability of pipeline capacity,
- 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
- the overall economic environment.

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 90% of our proved reserves are currently natural gas reserves, we are more affected by movements in natural gas prices.

Our level of indebtedness may adversely affect operations, and we may have difficulty repaying long-term indebtedness as it matures.

As of December 31, 2001, we had long-term indebtedness of $1.3 billion, which included no bank indebtedness. Our long-term indebtedness represented 63% of our total book capitalization at December 31, 2001.

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

- a significant portion of our cash flows must be used to service our indebtedness; for example, for the year ended December 31, 2001, interest (including capitalized interest) on our borrowings was $103.0 million and equaled approximately 17% of EBITDA. We cannot assure you that our business will generate sufficient cash flows from operations to enable us to continue to meet our obligations under our indentures.
- a high level of debt increases our vulnerability to general adverse economic and industry conditions,
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments,
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry, and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

We may incur additional debt, including significant secured indebtedness, in order to make future acquisitions or to develop our properties. A higher level of indebtedness increases the risk that we may default on our debt 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 cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future working capital, borrowings or equity financing will 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 annual redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. We cannot assure you that we will have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Higher oil and gas prices adversely affect the cost and availability of drilling and production services.

Higher oil and gas prices generally stimulate increased demand for drilling and production services and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. In the first nine months of 2001, we experienced significantly higher costs for drilling rigs and other related services. While we have recently experienced lower service costs as demand has decreased due to lower oil and gas prices, a return to higher prices would likely increase service costs once again.

Our industry is extremely competitive.

The energy industry is extremely competitive. This is especially true with regard to exploration for, and development and production of, new sources of oil and natural gas. As an independent producer of oil and natural gas, we frequently compete against companies that are larger and financially stronger in acquiring properties suitable for exploration, in contracting for drilling equipment and other services and in securing trained personnel.

Our commodity price risk management activities may reduce the realized prices received for our oil and gas sales.

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. These transactions are limited in life. While intended to reduce the effects of volatile oil and gas prices, commodity price risk management transactions may limit the prices we actually realize. We cannot assure you that we will not experience reductions to oil and gas revenues from our commodity price risk management activities in the future. 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 risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price risk management transactions exceed certain levels. At December 31, 2001, we were not required to post any collateral. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and highly volatile natural gas and oil prices.

Estimates of oil and gas reserves are uncertain and inherently imprecise.

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, 2001, approximately 29% by volume of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The estimates of these reserves include the assumption that we will make significant capital expenditures to develop the reserves, including $224 million in 2002. Although we have prepared estimates of our oil and gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the results will 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 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, 2001 present value is based on weighted average wellhead oil and gas prices of $18.82 per barrel of oil and $2.51 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. A change in price of $0.10 per mcf and $1.00 per barrel would result in a change in our December 31, 2001 present value of proved reserves of approximately $82 million and $16 million, respectively.

Any changes in consumption by oil and 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 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.

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, our proved reserves will decline over time. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We cannot assure you that we can successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

If we do not make significant capital expenditures, we may not be able to replace 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 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 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, there can be no assurance that additional bank debt, debt or equity issuances or other methods of financing will be available to meet these requirements.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.

Our recent growth is due in part to acquisitions of exploration and production companies and producing properties. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include 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. In addition, competition for producing oil and gas properties is intense and many of our competitors have financial and other resources which are substantially greater than those available to us. Therefore, we cannot assure you that we will be able to acquire oil and gas properties that contain economically recoverable reserves or that we will complete such acquisitions on acceptable terms.

Additionally, 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. While it is our current intention to continue to concentrate on acquiring properties with development and exploration potential located in the Mid-Continent region, there can be no assurance that in the future we will not decide to pursue acquisitions or properties located in other geographic regions. To the extent that such acquired properties are substantially different than our existing properties, our ability to efficiently realize the economic benefits of such transactions may be limited.

Oil and gas drilling and producing operations are hazardous and 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 occurs, we could sustain substantial losses as a result of:

- injury or loss of life,
- severe damage to or destruction of property, natural resources and equipment,
- pollution or other environmental damage,
- clean-up responsibilities,
- regulatory investigations and 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. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover casualty losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

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

We do not always encounter commercially productive reservoirs through our drilling operations. We cannot assure you that the new wells we drill or participate in will be productive or that we will recover all or any portion of our investment in wells drilled. 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:

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

The loss of key personnel could adversely affect our ability to operate.

We depend, and will continue to depend in the foreseeable future, on the services of our officers and key employees with extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties and marketing oil and gas production. Our ability to retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

REGULATION

General. Numerous departments and agencies, foreign, federal, state and local, issue rules and regulations binding on the oil and gas industry, some of which carry substantial penalties for failure to comply. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

Exploration and Production. Our domestic operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other domestic activities subject to regulation are:

- the location of wells,
- the method of drilling and completing wells,
- the surface use and restoration of properties upon which wells are drilled,
- the plugging and abandoning of wells,
- the disposal of fluids used or other wastes obtained in connection with operations,
- the marketing, transportation and reporting of production, and
- the valuation and payment of royalties.

Our operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells which may be drilled in a particular area) and the unitization or pooling of oil and gas properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, 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.

We do not anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Regulation. Various federal, foreign, 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. Such regulation has increased the cost of 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 require us to obtain permits for, among other things,

- discharges into surface waters,
- discharges of storm water runoff,
- the construction of facilities in wetland areas, 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, to suspend or cease operations in contaminated areas, or to perform remedial plugging operations to prevent future contamination. The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and nonhazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The Environmental Protection Agency, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

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

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and 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 substantial 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

At December 31, 2001, Chesapeake had federal and state income tax net operating loss (NOL) carryforwards of approximately $757.7 million. Additionally, we had approximately $419.8 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $5.7 million of percentage depletion carryforwards. The NOL carryforwards expire from 2010 through 2021. 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.

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. Chesapeake had ownership changes in January 1995 and March 1998 which triggered limitations. Certain NOLs acquired through various acquisitions are also subject to limitations. Of the $757.7 million NOLs and $419.8 million AMT NOLs, $339.5 million and $84.1 million, respectively, are limited under Section 382. Therefore, $418.2 million of the NOLs and $335.7 million of the AMT NOLs are not subject to the limitation. The utilization of $339.5 million of the NOLs and the utilization of $84.1 million of the AMT NOLs subject to the Section 382 limitation are limited to approximately $37.9 million and $12.3 million, respectively, each taxable year. Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2001. Equity transactions after the date hereof 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.

In the event of another ownership change, the amount of Chesapeake's NOLs available for use each year will depend upon future events that cannot currently be predicted and upon interpretation of complex rules under Treasury regulations. If less than the full amount of the annual limitation is utilized in any given year, the unused portion may be carried forward and may be used in addition to successive years' annual limitation.

We expect to utilize our NOL carryforwards and other tax deductions and credits to offset taxable income in the near 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. From time to time, Chesapeake's title to oil and gas properties is challenged through legal proceedings. We are routinely involved in litigation involving title to certain of our oil and gas properties, some of which management believes could be adverse to us, individually or in the aggregate. See Item 3 -- Legal Proceedings.

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, the occurrence of any of which could result in substantial losses to Chesapeake 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 can be no assurance that this insurance will be adequate to cover any losses or exposure to liability. We also carry comprehensive general liability policies and a $75 million umbrella policy. Chesapeake and our subsidiaries carry workers' compensation insurance in all states in which we operate and 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.

EMPLOYEES

Chesapeake had 677 employees as of December 31, 2001, including 107 employed by our drilling rig subsidiary, Nomac Drilling Corporation. No employees are represented by organized labor unions. We believe our employee relations are good.

FACILITIES

Chesapeake owns an office building complex in Oklahoma City and field offices in Lindsay and Waynoka, Oklahoma; Garden City, Kansas; and Borger, Texas. In addition, Chesapeake leases field office space in Forgan, Kingfisher, Oklahoma City, Watonga, Weatherford and Wilburton, Oklahoma; Navasota, Texas; Lovington and Eunice, New Mexico; and Dickinson, North Dakota.

GLOSSARY

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.

Compound Annual Growth Rate. Annual growth rate of a particular unit of measure or performance, expressed as an internal rate of return during a specified time interval (e.g., 1996-2001).

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.

EBITDA. Net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, Gothic standby credit facility costs, impairments of oil and gas properties and other assets, extraordinary items, risk management income and gain on sale of Canadian subsidiary and certain other non-cash charges. EBITDA is not a measure of cash flow as determined by generally accepted accounting principles. EBITDA information has been included in this report because EBITDA is a measure used by some investors in determining historical ability to service indebtedness. EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows as determined in accordance with generally accepted accounting principles as an indicator of operating performance or liquidity.

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.

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 interest owned in gross acres or gross wells.

NYMEX. New York Mercantile Exchange.

Operating Cash Flow. Income (loss) before income taxes, depreciation, depletion and amortization, Gothic standby credit facility costs, impairment of oil and gas properties and other assets, extraordinary items, risk management income, gain on Sale of Canadian subsidiary and certain other non-cash charges. Operating cash flow should not be considered as an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with generally accepted accounting principles as an indicator of operating performance or liquidity.

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.

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.

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 drilled to known reservoir on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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.

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 2. PROPERTIES

Chesapeake focuses its natural gas exploration, development and acquisition efforts in one primary operating area and in three secondary operating areas: (i) the Mid-Continent (consisting of Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle), representing 84% of our proved reserves, (ii) the Gulf Coast region consisting primarily of the Deep Giddings Field in Texas and the Austin Chalk and Tuscaloosa Trends in Louisiana, representing 8% of our proved reserves, (iii) the Permian Basin region of southeastern New Mexico, representing 5% of our proved reserves and (iv) the Williston Basin of eastern Montana and western North Dakota, representing 2% of our proved reserves. In October 2001, we sold our Canadian subsidiary which included all of our Canadian properties and leasehold.

During the year ended December 31, 2001, we participated in 530 gross (244.5 net) wells, 238 of which we operated. A summary of our development, exploration, acquisition and divestiture activities by operating area is as follows:

			CAPITAL EXPENDITURES -- OIL AND GAS PROPERTIES					
	GROSS WELLS DRILLED	NET WELLS DRILLED	DRILLING	LEASEHOLD	SUB-TOTAL	ACQUISITIONS	SALE OF PROPERTIES	TOTAL
			($ IN THOUSANDS)					
Mid-Continent	477	218.6	$ 282,830	$ 45,587	$ 328,417	$ 738,768	$ (1,138)	$ 1,066,047
Gulf Coast	21	9.4	41,847	9,910	51,757	1,874	--	53,631
Canada	18	8.0	10,225	873	11,098	--	(150,306)	(139,208)
Permian Basin	8	4.7	7,799	3,137	10,936	--	--	10,936
Williston Basin and other	6	3.8	4,508	257	4,765	--	--	4,765
Total	530	244.5	$ 347,209	$ 59,764	$ 406,973	$ 740,642	$ (151,444)	$ 996,171

Chesapeake's proved reserves increased 31% during 2001 to an estimated 1,780 bcfe at December 31, 2001, compared to 1,355 bcfe of estimated proved reserves at December 31, 2000 (see note 11 of notes to consolidated financial statements in Item 8).

Chesapeake's strategy for 2002 is to continue developing our natural gas assets through exploratory and developmental drilling and by selectively acquiring strategic properties in our core operating areas. We have budgeted approximately $300 million for drilling, acreage acquisition, seismic and related capitalized internal costs, all of which will be funded out of 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.

PRIMARY OPERATING AREAS

Mid-Continent. Chesapeake's Mid-Continent proved reserves of 1,501.5 bcfe represented 84% of our total proved reserves as of December 31, 2001, and this area produced 116.1 bcfe, or 72%, of our 2001 production. During 2001, we invested approximately $328.4 million to drill 477 (218.6 net) wells in the Mid-Continent. We anticipate spending approximately 80% to 85% of our total budget for exploration and development activities in the Mid-Continent region during 2002. We anticipate the Mid-Continent will contribute approximately 148.0 bcfe, or 88%, of expected total production during 2002.

SECONDARY OPERATING AREAS

Gulf Coast. Chesapeake's Gulf Coast proved reserves (consisting primarily of the Deep Giddings Field in Texas and the Austin Chalk and Tuscaloosa Trends in Louisiana) represented 142.7 bcfe, or 8%, of our total proved reserves as of December 31, 2001. During 2001, the Gulf Coast assets produced 27.5 bcfe, or 17%, of our total production. During 2001, we invested approximately $51.8 million to drill 21 (9.4 net) wells in the Gulf Coast. We anticipate the Gulf Coast will contribute approximately 22.0 bcfe, or 13%, of expected total production during 2002. We anticipate spending approximately 5% to 10% of our total budget for exploration and development activities in the Gulf Coast region during 2002.

Permian Basin. Chesapeake's Permian Basin proved reserves, consisting primarily of the Lovington area in New Mexico, represented 94.4 bcfe, or 5%, of our total proved reserves as of December 31, 2001. During 2001, the Permian assets produced 5.0 bcfe, or 3%, of our total production. We anticipate the Permian Basin will contribute approximately 7.7 bcfe, or 5%, of expected total production during 2002. During 2001, we invested approximately $10.9 million to drill 8 (4.7 net) wells in the Permian Basin. For 2002, we anticipate spending approximately 2% to 3% of our total budget for exploration and development activities in the Permian Basin.

Williston Basin. Chesapeake's Williston Basin proved reserves represented 29.8 bcfe, or 2%, of our total proved reserves as of December 31, 2001. During 2001, the Williston assets produced 3.3 bcfe, or 2% of our total production. We anticipate the Williston Basin will contribute approximately 1.5 bcfe, or 1.6%, of expected total production during 2002. During 2001, we invested approximately $4.1 million to drill 6 (3.8 net) wells in the Williston Basin. For 2002, we anticipate spending approximately 1% to 2% of our total budget for exploration and development activities in the Williston Basin.

Canada. During 2001, production from Canada was 9.1 bcfe, or 6%, of our total production. During 2001, we invested approximately $11.1 million to drill 18 (8.0 net) wells, install various pipelines and compressors and to perform capital workovers in Canada. On October 1, 2001, we sold our Canadian subsidiary for approximately $143.0 million, which resulted in a $27.0 million pre-tax gain. We decided to sell our Canadian assets because we believe Chesapeake can receive a greater return on its invested capital in the Mid-Continent region rather than in Canada.

OIL AND GAS RESERVES

The tables below set forth information as of December 31, 2001 with respect to our estimated proved reserves, and the associated estimated future net revenue and the present value at such date. Ryder Scott Company L.P. evaluated 26%, Lee Keeling and Associates evaluated 24%, and Williamson Petroleum Consultants, Inc. evaluated 22% of our combined discounted future net revenues from our estimated proved reserves at December 31, 2001. The remaining 28% was evaluated internally by our engineers. All estimates were prepared based upon a review of production histories and other geologic, economic, ownership and engineering data we developed. The present value of estimated future net revenue shown is not intended to represent the current market value of the estimated oil and gas reserves we own.

ESTIMATED PROVED RESERVES AS OF DECEMBER 31, 2001	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)
Proved developed	22,496	1,134,381	1,269,359
Proved undeveloped	7,597	465,005	510,587
Total proved	30,093	1,599,386	1,779,946

ESTIMATED FUTURE NET REVENUE AS OF DECEMBER 31, 2001(a)	PROVED DEVELOPED	PROVED UNDEVELOPED	TOTAL PROVED
		($ IN THOUSANDS)	
Estimated future net revenue	$2,300,592	$ 665,440	$2,966,032
Present value of future net revenue	$1,312,865	$ 333,802	$1,646,667

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(a) Estimated future net revenue represents 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, 2001. The amounts shown do not give 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. The prices used in the external and internal reports yield weighted average wellhead prices of $18.82 per barrel of oil and $2.51 per mcf of gas.

The future net revenue attributable to our estimated proved undeveloped reserves of $665 million at December 31, 2001, and the $334 million present value thereof, have been calculated assuming that we will expend approximately $420 million 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.

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, 2001. 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 cost, that may not prove correct. Predictions about prices and future production levels are subject to great uncertainty, and 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.

See Item 1 and note 11 of notes to consolidated financial statements included in Item 8 for a description of drilling, production and other information regarding our oil and gas properties.

ITEM 3. LEGAL PROCEEDINGS

We are subject to ordinary routine litigation incidental to our business. In addition, the following matters were recently terminated or are pending:

West Panhandle Field Cessation Cases. One of our subsidiaries, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. have been defendants in 16 lawsuits filed between June 1997 and December 2001 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which we acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees.

The plaintiffs in these cases have claimed the leases terminated upon the cessation of production for various periods, primarily during the 1960s. In addition, the plaintiffs have sought to recover conversion damages, exemplary damages, attorneys' fees and interest. The defendants have asserted that any cessation of production was excused and have pled affirmative defenses of limitations, waiver, temporary estoppel, laches and title by adverse possession. As previously reported, four of the 16 cases have been tried, and there have been appellate decisions in three of them.

In January 2001, CP and the other defendants settled the claims of the principal plaintiffs in eight cases tried or pending in the District Court of Moore County, Texas, 69th Judicial District. The settlement consideration was not material to our financial condition or results of operations. In two of these cases, we have filed petitions for review in the Texas Supreme Court with respect to the claims of plaintiffs who were not covered by the settlement. The Texas Supreme Court granted the petitions in December 2001 and heard oral arguments in March 2002.

Related West Panhandle cessation cases which are pending are the following:

Lois Law, et al. v. NGPL, et al., District Court of Moore County, Texas, 69th Judicial District, No. 97-70, filed December 22, 1997, jury trial in June 1999, verdict for CP and co-defendants. The jury found plaintiffs' claims were barred by adverse possession, laches and revivor. On January 19, 2000, the court granted plaintiffs' motion for judgment notwithstanding verdict and entered judgment in favor of plaintiffs. In addition to quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs, the court awarded actual damages against CP in the amount of $716,400 and exemplary damages in the amount of $25,000. The court further awarded, jointly and severally from all defendants, $160,000 in attorneys' fees and interest and court costs. On March 28, 2001, the Amarillo Court of Appeals reversed and rendered judgment in favor of CP and the other defendants, finding that the subject leases had been revived as a matter of law, making all other issues moot. Plaintiffs have petitioned the Texas Supreme Court to accept the case for review. The Texas Supreme Court has asked for briefs but has not yet ruled on the petition.

A.C. Smith, et al. v NGPL, et al., District Court of Moore County, Texas, 69th Judicial District, No. 98-47, first filed January 26, 1998, refiled May 29, 1998. On June 18, 1999, the court granted plaintiffs' motion for summary judgment in part, finding that the lease had terminated due to the cessation of production, subject to the defendants' affirmative defenses. On February 8, 2001, the court granted plaintiffs' motion for summary judgment on defendants' affirmative defenses but reversed its ruling that the lease had terminated as a matter of law. No trial date has been set.

Phillip Thompson, et al. v. NGPL, et al., U.S. District Court, Northern District of Texas, Amarillo Division, Nos. 2:98-CV-012 and 2:98-CV-106, filed January 8, 1998 and March 18, 1998, respectively (actions consolidated), jury trial in May 1999, verdict for CP and co-defendants. The jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches and revivor. Plaintiffs' motion for new trial pending.

Craig Fuller, et al. v. NGPL, et al., District Court of Carson County, Texas, 100th Judicial District, No. 8456, filed June 23, 1997, cross motions for summary judgment pending.

Pace v. NGPL, et al., U.S. District Court, Northern District of Texas, Amarillo Division, filed January 29, 1999. Cross motions for summary judgment pending.

The remaining three cases were filed in September 2001 in the U.S. District Court, Northern District of Texas, Amarillo Division, in November 2001 in the District Court of Moore County, Texas, 69th Judicial District and in December 2001 in the District Court of Carson County, Texas, 100th Judicial District. CP and the other defendants have filed answers in each of them.

We have previously established an accrued liability we believe will be sufficient to cover the estimated costs of litigation for each of the pending cases. Because of the inconsistent verdicts reached by the juries in the four cases tried to date and because the amount of damages sought is not specified in all of the pending cases, the outcome of any future trials and the amount of damages that might ultimately be awarded could differ from management's estimates. CP and the other defendants are vigorously defending against the plaintiffs' claims.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

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, 2000:		
First Quarter	$ 3.31	$ 1.94
Second Quarter	8.00	2.75
Third Quarter	8.25	5.31
Fourth Quarter	10.50	5.44
YEAR ENDED DECEMBER 31, 2001:		
First Quarter	$11.06	$ 7.65
Second Quarter	9.45	6.20
Third Quarter	6.96	4.50
Fourth Quarter	7.59	5.26

At March 22, 2002 there were 1,209 holders of record of our common stock and approximately 52,000 beneficial owners.

DIVIDENDS

We did not pay dividends on our common stock in 2000 or 2001. The payment of future cash dividends, if any, will depend upon, among other things, our financial condition, funds from operations, the level of our capital and development expenditures, our future business prospects and any contractual restrictions. Other than payments of dividends on preferred stock, our current policy is to retain cash for the continued growth of our business.

Two 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 the 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.

From December 31, 1998 through March 31, 2000, we did not meet the debt incurrence test contained in one of our indentures, which required a coverage ratio of at least 2.5 to 1. As a result, we were unable to pay dividends on our previously outstanding 7% cumulative convertible preferred stock. Beginning June 30, 2000, we met the debt incurrence test and resumed paying quarterly preferred stock dividends on November 1, 2000. The 7% preferred stock was redeemed and retired in 2001. On November 13, 2001, we issued 3.0 million shares of 6.75% cumulative preferred stock, par value $.01 per share and a liquidation preference of $50 per share, in a private offering. Annual cumulative cash dividends of $3.375 per share are payable quarterly on the fifteenth day of each February, May, August and November. As of December 31, 2001, our coverage ratio for purposes of the debt incurrence test was 6.3 to 1, compared to 2.25 to 1 required in our indentures.

Our revolving credit agreement limits the amount of cash dividends we may pay to $10.0 million per year, excluding dividends on our 6.75% cumulative preferred stock. The lending group has consented to the payment of these preferred stock dividends as long as there is no default under the credit agreement when dividends are declared.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data of Chesapeake for the fiscal year ended June 30, 1997, the six months ended December 31, 1996, the six month transition period ended December 31, 1997 and the twelve months ended December 31, 1997, 1998, 1999, 2000 and 2001. The data are derived from our audited consolidated financial statements, although the period for the six months ended December 31, 1996 and the twelve months ended December 31, 1997 have not been audited. In 1997, we changed our fiscal year from June 30 to

December 31. Acquisitions we made during the first and second quarters of 1998 and the first quarter of 2001 materially affect the comparability of the selected financial data with the respective prior years. Each of the acquisitions was accounted for using the purchase method. 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.

	YEAR ENDED JUNE 30, 1997	SIX MONTHS ENDED DECEMBER 31, 1996	SIX MONTHS ENDED DECEMBER 31, 1997
		(UNAUDITED)	
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)		
STATEMENT OF OPERATIONS DATA:			
Revenues:			
Oil and gas sales	$ 192,920	$ 90,167	$ 95,657
Risk management income	--	--	--
Oil and gas marketing sales	76,172	30,019	58,241
Total revenues	269,092	120,186	153,898
Operating costs:			
Production expenses	11,445	4,268	7,560
Production taxes	3,662	1,606	2,534
General and administrative	8,802	3,739	5,847
Oil and gas marketing expenses	75,140	29,548	58,227
Oil and gas depreciation, depletion and amortization	103,264	36,243	60,408
Depreciation and amortization of other assets	3,782	1,836	2,414
Impairment of oil and gas properties	236,000	--	110,000
Impairment of other assets	--	--	--
Total operating costs	442,095	77,240	246,990
Income (loss) from operations	(173,003)	42,946	(93,092)
Other income (expense):			
Interest and other income	11,223	2,516	78,966
Interest expense	(18,550)	(6,216)	(17,448)
Impairment of investments in securities	--	--	--
Gain on sale of Canadian subsidiary	--	--	--
Gothic standby credit facility costs	--	--	--
Total other income (expense)	(7,327)	(3,700)	61,518
Income (loss) before income taxes and extraordinary item	(180,330)	39,246	(31,574)
Provision (benefit) for income taxes	(3,573)	14,325	--
Income (loss) before extraordinary item	(176,757)	24,921	(31,574)
Extraordinary item:			
Loss on early extinguishment of debt, net of applicable income taxes	(6,620)	(6,443)	--
Net income (loss)	(183,377)	18,478	(31,574)
Preferred stock dividends	--	--	--
Gain on redemption of preferred stock	--	--	--
Net income (loss) available to common shareholders	$(183,377)	$ 18,478	$ (31,574)
Earnings (loss) per common share -- basic:			
Income (loss) before extraordinary item	$ (2.69)	$ 0.40	$ (0.45)
Extraordinary item	(0.10)	(0.10)	--
Net income (loss)	$ (2.79)	$ 0.30	$ (0.45)
Earnings (loss) per common share -- assuming dilution:			
Income (loss) before extraordinary item	$ (2.69)	$ 0.38	$ (0.45)
Extraordinary item	(0.10)	(0.10)	--
Net income (loss)	$ (2.79)	$ 0.28	$ (0.45)
Cash dividends declared per common share	$ 0.02	$ --	$ 0.04
CASH FLOW DATA:			
Cash provided by operating activities before changes in working capital	$ 161,140	$ 76,816	$ 67,872
Cash provided by operating activities	84,089	41,901	139,157
Cash used in investing activities	523,854	184,149	136,504
Cash provided by (used in) financing activities	512,144	231,349	(2,810)
Effect of exchange rate changes on cash	--	--	--
BALANCE SHEET DATA (at end of period):			
Total assets	$ 949,068	$ 860,597	$ 952,784
Long-term debt, net of current maturities	508,950	220,149	508,992

Stockholders' equity (deficit)	286,889	484,062	280,206

	YEARS ENDED DECEMBER 31,				
	1997	1998	1999	2000	2001
	(UNAUDITED)	($ IN THOUSANDS, EXCEPT PER SHARE DATA)			
STATEMENT OF OPERATIONS DATA:					
Revenues:					
Oil and gas sales	$ 198,410	$ 256,887	$ 280,445	$ 470,170	$ 735,529
Risk management income	--	--	--	--	84,789
Oil and gas marketing sales	104,394	121,059	74,501	157,782	148,733
Total revenues	302,804	377,946	354,946	627,952	969,051
Operating costs:					
Production expenses	14,737	51,202	46,298	50,085	75,374
Production taxes	4,590	8,295	13,264	24,840	33,010
General and administrative	10,910	19,918	13,477	13,177	14,449
Oil and gas marketing expenses	103,819	119,008	71,533	152,309	144,373
Oil and gas depreciation, depletion and amortization	127,429	146,644	95,044	101,291	172,902
Depreciation and amortization of other assets	4,360	8,076	7,810	7,481	8,663
Impairment of oil and gas properties	346,000	826,000	--	--	--
Impairment of other assets	--	55,000	--	--	--
Total operating costs	611,845	1,234,143	247,426	349,183	448,771
Income (loss) from operations	(309,041)	(856,197)	107,520	278,769	520,280
Other income (expense):					
Interest and other income	87,673	3,926	8,562	3,649	2,877
Interest expense	(29,782)	(68,249)	(81,052)	(86,256)	(98,321)
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)	57,891	(64,323)	(72,490)	(82,607)	(81,915)
Income (loss) before income taxes and extraordinary item	(251,150)	(920,520)	35,030	196,162	438,365
Provision (benefit) for income taxes	(17,898)	--	1,764	(259,408)	174,959
Income (loss) before extraordinary item	(233,252)	(920,520)	33,266	455,570	263,406
Extraordinary item:					
Loss on early extinguishment of debt, net of applicable income taxes	(177)	(13,334)	--	--	(46,000)
Net income (loss)	(233,429)	(933,854)	33,266	455,570	217,406
Preferred stock dividends	--	(12,077)	(16,711)	(8,484)	(2,050)
Gain on redemption of preferred stock	--	--	--	6,574	--
Net income (loss) available to common shareholders	$ (233,429)	$ (945,931)	$ 16,555	$ 453,660	$ 215,356
Earnings (loss) per common share -- basic:					
Income (loss) before extraordinary item	$ (3.30)	$ (9.83)	$ 0.17	$ 3.52	$ 1.61
Extraordinary item	--	(0.14)	--	--	(0.28)
Net income (loss)	$ (3.30)	$ (9.97)	$ 0.17	$ 3.52	$ 1.33
Earnings (loss) per common share -- assuming dilution:					
Income (loss) before extraordinary item	$ (3.30)	$ (9.83)	$ 0.16	$ 3.01	$ 1.51
Extraordinary item	--	(0.14)	--	--	(0.26)
Net income (loss)	$ (3.30)	$ (9.97)	$ 0.16	$ 3.01	$ 1.25
Cash dividends declared per common share	$ 0.06	$ 0.04	$ --	$ --	$ --
CASH FLOW DATA:					
Cash provided by operating activities before changes in working capital	$ 152,196	$ 117,500	$ 138,727	$ 305,804	$ 518,563
Cash provided by operating activities	181,345	94,639	145,022	314,640	553,737
Cash used in investing activities	476,209	548,050	153,908	325,229	670,105
Cash provided by (used in) financing activities	277,985	363,797	13,102	(27,740)	234,507
Effect of exchange rate changes on cash	--	(4,726)	4,922	(329)	(545)
BALANCE SHEET DATA (at end of period):					
Total assets	$ 952,784	$ 812,615	$ 850,533	$ 1,440,426	$ 2,286,768
Long-term debt, net of current maturities	508,992	919,076	964,097	944,845	1,329,453
Stockholders' equity (deficit)	280,206	(248,568)	(217,544)	313,232	767,407

ITEM 7. 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 gas sales, average sales prices received and expenses for the periods indicated:

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
NET PRODUCTION:			
Oil (mbbl)	4,147	3,068	2,880
Gas (mmcf)	108,610	115,771	144,171
Gas equivalent (mmcfe)	133,492	134,179	161,451
OIL AND GAS SALES ($ IN THOUSANDS):			
Oil	$ 66,413	$ 80,953	$ 77,522
Gas	214,032	389,217	658,007
Total oil and gas sales	$280,445	$470,170	$735,529
AVERAGE SALES PRICE:			
Oil ($ per bbl)	$ 16.01	$ 26.39	$ 26.92
Gas ($ per mcf)	$ 1.97	$ 3.36	$ 4.56
Gas equivalent ($ per mcfe)	$ 2.10	$ 3.50	$ 4.56
EXPENSES ($ PER mcfe):			
Production expenses and taxes	$ 0.45	$ 0.56	$ 0.67
General and administrative	$ 0.10	$ 0.10	$ 0.09
Depreciation, depletion and amortization	$ 0.71	$ 0.75	$ 1.07
NET WELLS DRILLED	120	177	245
NET WELLS AT END OF PERIOD	2,242	2,697	3,572

RESULTS OF OPERATIONS

General. For the year ended December 31, 2001, Chesapeake had net income of $217.4 million, or $1.25 per diluted common share, on total revenues of $969.1 million. This compares to net income of $455.6 million, or $3.01 per diluted common share, on total revenues of $628.0 million during the year ended December 31, 2000, and net income of $33.3 million, or $0.16 per diluted common share, on total revenues of $354.9 million during the year ended December 31, 1999. The 2001 net income included, on a pre-tax basis except for the extraordinary item, $84.8 million in risk management income, a $10.1 million impairment of certain equity investments, a $27.0 million gain on the sale of our Canadian subsidiary, a $3.4 million cost for an unsecured standby credit facility associated with the acquisition of Gothic Energy Corporation, and a $46.0 million extraordinary after-tax loss on early extinguishment of debt. Net income in 2000 was significantly enhanced by the reversal of a deferred tax valuation allowance in the amount of $265.0 million during the fourth quarter. The reversal related to Chesapeake's expected ability to generate sufficient future taxable income to utilize net operating losses prior to their expiration.

Oil and Gas Sales. During 2001, oil and gas sales increased to $735.5 million versus $470.2 million in 2000 and $280.4 million in 1999. In 2001, Chesapeake produced 161.5 bcfe at a weighted average price of $4.56 per mcfe, compared to 134.2 bcfe produced in 2000 at a weighted average price of $3.50 per mcfe, and 133.5 bcfe produced in 1999 at a weighted average price of $2.10 per mcfe.

The following table shows our production by region for 1999, 2000 and 2001:

	YEARS ENDED DECEMBER 31,					
	1999		2000		2001	
	mmcfe	PERCENT	mmcfe	PERCENT	mmcfe	PERCENT
Mid-Continent	68,170	51%	78,342	58%	116,133	72%
Gulf Coast	43,909	33	35,154	26	27,531	17
Canada	11,737	9	12,076	9	9,075	6
Permian Basin	5,722	4	6,166	5	5,029	3
Williston Basin and Other	3,954	3	2,441	2	3,683	2
Total production	133,492	100%	134,179	100%	161,451	100%

Natural gas production represented approximately 89% of our total production volume on an equivalent basis in 2001, compared to 86% in 2000 and 81% in 1999. The decrease in oil production from 1999 through 2001 is the result of divestitures that occurred primarily in 1999 and our increasing focus on natural gas.

For 2001, we realized an average price per barrel of oil of $26.92, compared to $26.39 in 2000 and $16.01 in 1999. Natural gas prices per mcf were $4.56, $3.36 and $1.97 in 2001, 2000 and 1999, respectively. Our hedging activities resulted in an increase in oil and gas revenues of $105.4 million or $0.65 per mcfe in 2001, a decrease of $30.6 million or $0.23 per mcfe in 2000, and a decrease of $1.7 million or $0.01 per mcfe in 1999.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement 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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. 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. 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. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow hedge are also recognized in earnings through risk management income.

Risk Management Income. Chesapeake recognized $84.8 million of risk management income in 2001, compared to no such income (loss) in 2000 and 1999. Risk management income for 2001 consisted of $106.8 million related to changes in fair value of derivatives not designated as cash flow hedges less $24.5 million of reclassifications related to the settlement of such contracts plus $2.5 million associated with the ineffective portion of derivatives qualifying for hedge accounting.

Pursuant to SFAS 133, our cap-swaps do not qualify for designation as cash flow hedges. Therefore, changes in fair value of these instruments that occur prior to their maturity, together with any change in fair value of cash flow hedges resulting from ineffectiveness, are reported in the statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

Oil and Gas Marketing Sales. Chesapeake realized $148.7 million in oil and gas marketing sales for third parties in 2001, with corresponding oil and gas marketing expenses of $144.4 million, for a net margin of $4.3 million. This compares to sales of $157.8 million and $74.5 million, expenses of $152.3 million and $71.5 million, and margins of $5.5 million and $3.0 million in 2000 and 1999, respectively. In 2001, Chesapeake realized an increase in volumes related to oil and gas marketing sales, which was partially offset by a decrease in oil and gas prices. The increase in marketing sales and cost of sales in 2000 as compared to 1999 was due primarily to higher oil and gas prices in 2000 and the fact that we began marketing oil in June 1999.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $75.4 million in 2001, compared to $50.1 million and $46.3 million in 2000 and 1999, respectively. On a unit of production basis, production expenses were $0.47 per mcfe in 2001 compared to $0.37 and $0.35 per mcfe in 2000 and 1999, respectively. The increase in costs on a per unit basis in 2001 is due primarily to increased field service costs, higher production costs associated with properties acquired in 2001 and an increase in ad valorem taxes. We expect that lease operating expenses per mcfe in 2002 will range from $0.50 to $0.55.

Production Taxes. Production taxes were $33.0 million in 2001 compared to $24.8 million in 2000 and $13.3 million in 1999. On a unit of production basis, production taxes were $0.20, $0.19 and $0.10 per mcfe in 2001, 2000 and 1999, respectively. The increase in 2001 of $8.2 million was due to an increase in production volumes and, to a lesser extent, an increase in the average wellhead prices received for natural gas in 2001. The increase from 1999 to 2000 was the result of increased prices. 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 $0.18 to $0.22 in 2002 based on our assumption that oil and natural gas wellhead prices will range from $2.50 to $3.20 per mcfe.

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 $14.4 million in 2001, $13.2 million in 2000 and $13.5 million in 1999. The increase in 2001 is the result of the company's growth related to the various acquisitions which occurred in late 2000 and during 2001.

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 $8.3 million, $7.0 million and $2.7

million of internal costs in 2001, 2000 and 1999, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for 2002 will be between $0.10 and $0.11 per mcfe, which is approximately the same level as 2001.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $172.9 million, $101.3 million and $95.0 million during 2001, 2000 and 1999, 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 $1.07 ($1.08 in U.S. and $0.90 in Canada), $0.75 ($0.76 in U.S. and $0.71 in Canada) and $0.71 ($0.73 in U.S. and $0.52 in Canada) in 2001, 2000 and 1999, respectively. We expect the 2002 DD&A rate to be between $1.15 and $1.25 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $8.7 million in 2001, compared to $7.5 million in 2000 and $7.8 million in 1999. The increase in 2001 was primarily the result of higher depreciation cost on fixed assets related to recent capital expenditures. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from five to seven years.

Interest and Other Income. Interest and other income was $2.9 million, $3.6 million and $8.6 million in 2001, 2000 and 1999, respectively. The decrease in 2001 was the result of a decrease in miscellaneous non-oil and gas income offset by an increase in interest income. The decrease in 2000 was due primarily to gains on sales of various non-oil and gas assets during 1999 which did not occur in 2000.

Interest Expense. Interest expense increased to $98.3 million in 2001, compared to $86.3 million in 2000 and $81.1 million in 1999. The increase in 2001 is due to a $260.0 million increase in average long-term borrowings in 2001 compared to 2000, partially offset by a decrease in the overall average interest rate. The increase in 2000 compared to 1999 was due to additional borrowings under our bank credit facility. In addition to the interest expense reported, we capitalized $4.7 million of interest during 2001, compared to $2.4 million capitalized in 2000, and $3.5 million capitalized in 1999 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. We anticipate that capitalized interest for 2002 will be between $5.0 million and $6.0 million.

Impairments of Investments in Securities. During 2001 we recorded impairments to two equity investments of $10.1 million. The majority of this impairment was related to our investment in RAM Energy, Inc. In March 2001, we issued 1.1 million shares of Chesapeake common stock in exchange for 49.5% of RAM's outstanding common stock. Our shares were valued at $8.854 each, or $9.9 million in total. During 2001, we recorded our equity in RAM's net losses, which had the effect of reducing our carrying value in these securities to $8.6 million. In December 2001, we sold the RAM shares for minimal consideration. In addition, we reduced the carrying value of our $2.0 million investment in an Internet-based oil and gas business by $1.5 million to $0.5 million.

Gain on Sale of Canadian Subsidiary. In October 2001, we sold our Canadian subsidiary, which had oil and gas operations primarily in northeast British Columbia, for approximately $143.0 million. Under full-cost accounting, our investment in these Canadian oil and gas properties was treated as a separate cost center for accounting purposes. As a result of the sale of this cost center, any gain or loss on the disposition is required to be recognized currently in earnings. In the fourth quarter of 2001, we recorded a gain on sale of our Canadian subsidiary of $27.0 million.

Gothic Standby Credit Facility Costs. During 2000, we obtained a standby commitment for a $275 million credit facility, consisting of a $175 million term loan and a $100 million revolving credit facility which, if needed, would have replaced our then existing revolving credit facility. The term loan was available to provide funds to repurchase any of Gothic Production Corporation's 11.125% senior secured notes tendered following the closing of the Gothic acquisition in January 2001 pursuant to a change-of-control offer to purchase. In February 2001, we purchased $1.0 million of notes tendered for 101% of such amount. We did not use the standby credit facility and the commitment terminated on February 23, 2001. Chesapeake incurred $3.4 million of costs for the standby facility, which were recognized in the first quarter of 2001.

Extraordinary Loss on Early Extinguishment of Debt. During 2001, we purchased or redeemed $500.0 million principal amount of our 9.625% senior notes, $202.3 million principal amount of the 11.125% senior secured notes of Gothic Production Corporation, a Chesapeake subsidiary, and all $120.0 million principal amount of our 9.125% senior notes. The purchase and redemption of these notes included payment of aggregate make-whole and redemption premiums of $75.6 million and the write-off of unamortized debt costs and debt issue premiums. These costs associated with early extinguishment of debt are reflected as a $46.0 million after-tax extraordinary loss in 2001.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $175.0 million in 2001, compared to income tax benefit of $259.4 million in 2000 and income tax expense of $1.8 million in 1999. Income tax expense for 2001 is comprised of $158.3 million related to our domestic operations, $7.1 million related to our Canadian operations and $9.6 million related to the sale of our Canadian subsidiary. The income tax benefit in 2000 was comprised of $5.6 million of income tax expense related to our Canadian operations and the reversal of a $265 million deferred tax valuation allowance which was established in prior years. The valuation allowance had been established due to uncertainty surrounding our ability to utilize extensive regular tax NOLs prior to their expiration. Based upon our results of operations as of December 31, 2000, the improved outlook for the natural gas industry and our projected results of future operations, we believed it was more likely than not that Chesapeake would be able to generate sufficient future taxable income to utilize our existing NOLs prior to their expiration. Consequently, we determined that a valuation allowance was no longer required at December 31, 2000. Our expectations remain unchanged as of December 31, 2001. The income tax expense recorded in 1999 was related entirely to our Canadian operations.

CASH FLOWS FROM OPERATING, INVESTING AND FINANCING ACTIVITIES

Cash Flows from Operating Activities. Cash provided by operating activities (exclusive of changes in working capital) was $518.6 million in 2001, compared to $305.8 million in 2000 and $138.7 million in 1999. The $212.8 million increase from 2000 to 2001 was primarily due to increased oil and gas revenues resulting from higher sales volume and higher prices. The $167.1 million increase from 1999 to 2000 was primarily due to increased oil and gas revenues resulting from higher prices.

Cash Flows from Investing Activities. Cash used in investing activities increased to $670.1 million in 2001, compared to $325.2 million in 2000 and $153.9 million in 1999. During 2001, Chesapeake invested $421.0 million for exploration and development drilling, invested $316.7 million for the acquisition of oil and gas properties, received $1.4 million related to divestitures of oil and gas properties and received $142.9 million for the sale of our Canadian subsidiary. In 2001, we invested $40.2 million in securities of other companies, including $22.5 million in notes and warrants of Seven Seas Petroleum Inc., $14.6 million in notes of RAM Energy, Inc. and $3.1 million in other equity securities. We also invested $14.1 million in drilling rig equipment, $11.0 million in our Oklahoma City office complex and $10.6 million on upgrading various other properties and equipment.

During 2000, Chesapeake invested $188.8 million for exploration and development drilling, invested $78.9 million for the acquisition of oil and gas properties, and received $1.5 million related to divestitures of oil and gas properties. We invested $36.7 million in connection with our acquisition of Gothic Energy Corporation, including the purchase of Gothic notes and acquisition related costs. We also invested $7.9 million in drilling rig equipment. Additionally in 2000, we invested $4.0 million in our Oklahoma City office complex. In 1999, we invested $153.3 million for exploration and development drilling, invested $49.9 million for the acquisition of oil and gas properties, and received $45.6 million related to divestitures of oil and gas properties.

Cash Flows from Financing Activities. Cash provided by financing activities was $234.5 million in 2001, compared to $27.7 million used in 2000 and $13.1 million provided in 1999. During 2001, we borrowed $433.5 million under our bank credit facility and made repayments under this facility of $458.5 million. In 2001, we received $780.6 million from the issuance of our $800.0 million 8.125% senior notes in April and $247.7 million from the issuance of our $250.0 million 8.375% senior notes in November. We used $906.0 million to purchase or redeem various Chesapeake and Gothic senior notes. We incurred $6.6 million of deferred charges related to our credit facility. In November 2001, we issued $150.0 million in preferred stock and received $145.1 million of net proceeds. We received $3.2 million from the exercise of employee and director stock options. We paid $3.3 million for make-whole provisions in the fourth quarter 2001 related to the exchange of our common stock for RAM Energy, Inc. common stock which occurred in March 2001. Preferred stock dividends of $1.1 million were paid in 2001.

During 2000, we borrowed $244.0 million under our bank credit facility and made repayments under this facility of $262.5 million. Also in 2000, we paid $8.3 million in connection with exchanges of our preferred stock for our common stock and paid cash dividends of $4.6 million on our preferred stock. In connection with our purchase of Gothic notes in 2000, we received $7.1 million cash from the sellers of Gothic notes pursuant to make-whole provisions included in the purchase agreements. These provisions required payments to be made by the sellers to us, or additional payments to be made by us to the sellers, depending upon changes in market value of our common stock during a specified period pending registration of our common stock issued to the sellers of Gothic notes. During 1999, we borrowed $116.5 million under our bank credit facility and made repayments under this facility of $98.0 million.

LIQUIDITY AND CAPITAL RESOURCES

Sources of Liquidity

Chesapeake had working capital of $188.0 million at December 31, 2001, of which $125.0 million was cash. Another source of liquidity is our $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. We believe we will have adequate resources, including budgeted operating cash flows, working capital and proceeds from our revolving bank credit facility, to fund our capital expenditure budget for exploration and development activities during 2002, which is currently estimated to be approximately $300 million. However, higher drilling and field operating costs, unfavorable drilling results or other factors could cause us to reduce our drilling program, which is largely discretionary. Based on our current cash flow assumptions, we expect operating cash flow to be between $325 million and $350 million. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes in 2002.

A significant portion of our liquidity is concentrated in cash and cash equivalents, including restricted cash, and 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. Our mark-to-market position and closed but uncollected receivable with our largest counterparty, Morgan Stanley Capital Group Inc., totaled $137.8 million at December 31, 2001. We do not expect that Morgan Stanley or our other counterparties will fail to meet their obligations given their high credit ratings. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. 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. The 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. Cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

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.

Contractual Obligations and Commercial Commitments

We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of December 31, 2001, we had no outstanding borrowings under this facility and had $1.1 million of the facility securing various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly.

The credit facility agreement contains various covenants and restrictive provisions including incurring additional indebtedness, selling properties, paying dividends, purchasing or redeeming our capital stock, making investments or loans or purchasing certain of our senior notes, creating liens, and making acquisitions. The credit facility agreement requires us to maintain a current ratio of at least 1 to 1 and a fixed charge coverage ratio of at least 2.5 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 or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration 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 $5.0 million.

As of December 31, 2001, senior notes represented $1.3 billion of our long-term debt and consisted of the following: $800.0 million principal amount of 8.125% senior notes due 2011, $250.0 million principal amount of 8.375% senior notes due 2008, $150.0 million principal amount of 7.875% senior notes due 2004 and $142.7 million principal amount of 8.5% senior notes due 2012. There are no scheduled principal payments required on any of the senior notes until March 2004, when $137.0 million is due, as a result of the repurchase and retirement of

$13.0 million of our 7.875% senior notes in March 2002. Debt ratings for the senior notes are B1 by Moody's Investor Service, B+ by Standard & Poor's Ratings Services and BB- by Fitch Ratings as of December 31, 2001. Debt ratings for our secured bank credit facility are Ba3 by Moody's Investor Service, BB by Standard & Poor's Ratings Services and BB+ by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly owned subsidiaries except Chesapeake Energy Marketing, Inc. guarantee the notes. The 7.875% senior notes are redeemable at our option at any time prior to March 15, 2004 at the make-whole price determined in accordance with the indenture. On or after March 15, 2004, we may redeem the 8.5% senior notes at the redemption price set forth in the indenture. We may redeem all or some of the 8.125% senior notes at any time on and after April 1, 2006 at the redemption prices set forth in the indenture and prior to such date pursuant to make-whole provisions in the indenture. We may redeem the 8.375% senior notes at any time on and after November 1, 2005 at the redemption prices set forth in the indenture and prior to such date pursuant to make-whole provisions in the indenture. If we repurchase at least $75 million of the 7.875% senior notes by August 31, 2003, we may extend the bank credit facility until June 2005 for an amount equal to the total revolving credit facility commitment less the outstanding amount of the 7.875% senior notes plus $50 million.

The indentures for the 8.125% and 8.375% senior notes 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; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not affect our ability to borrow under or expand our secured credit facility. As of December 31, 2001, we estimate that secured commercial bank indebtedness of approximately $383 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., an unrestricted subsidiary.

The table below summarizes our contractual obligations and commercial commitments as of December 31, 2001:

CONTRACTUAL OBLIGATIONS	PAYMENTS DUE BY PERIOD ($ IN THOUSANDS) LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	AFTER 5 YEARS	TOTAL
Long-term debt	$ 602	$ 150,000	$ --	$ 1,192,665	$ 1,343,267
Capital lease obligations	--	--	--	--	--
Operating leases	1,336	1,494	--	--	2,830
Unconditional purchase obligations	--	--	--	--	--
Other long-term obligations	--	--	--	--	--
Total contractual cash obligations ...	$ 1,938	$ 151,494	$ --	$ 1,192,665	$ 1,346,097

OTHER COMMERCIAL COMMITMENTS	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD ($ IN THOUSANDS) LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	OVER 5 YEARS	TOTAL AMOUNTS COMMITTED
Lines of credit	$ --	$ --	$ --	$ --	$ --
Standby letters of credit	3,396	--	--	--	3,396
Guarantees	--	--	--	--	--
Standby repurchase obligations	--	--	--	--	--
Other commercial commitments	--	1,200	--	--	1,200
Total commercial commitments	$ 3,396	$ 1,200	$ --	$ --	$ 4,596

Some of our commodity price risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price risk management transactions exceed certain levels. At December 31, 2001, we were not required to post any collateral. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and highly volatile natural gas and oil prices.

Investing and Financing Transactions During 2001

We completed the acquisition of Gothic Energy Corporation on January 16, 2001 by merging a wholly-owned subsidiary into Gothic. We issued a total of 4.0 million common shares in the merger. Gothic shareholders (other than Chesapeake) received 0.1908 of a share of Chesapeake common stock for each share of Gothic common stock. In addition, outstanding warrants and options to purchase Gothic common stock were converted to the right to purchase Chesapeake common stock based on the merger exchange ratio. As of December 31, 2001, 1.1 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $12.48 per share. In 2000, Chesapeake purchased substantially all of Gothic's 14.125% senior secured discount notes for total consideration of $80.8 million in cash and Chesapeake common stock. We also purchased $31.6 million principal amount of 11.125% senior secured notes due 2005 issued by Gothic's operating subsidiary for total consideration of $34.8 million in cash and Chesapeake common stock. Subsequent to the acquisition, we redeemed all remaining Gothic 14.125% discount notes for total consideration of $243,000. In February 2001, we purchased $1.0 million principal amount of Gothic senior secured notes tendered pursuant to a change-of-control offer at a purchase price of 101%. During April and May 2001, we purchased or redeemed the remaining $202.3 million of Gothic 11.125% senior secured notes for total consideration of $225.9 million. On May 14, 2001, Gothic Energy Corporation and Gothic Production Corporation became guarantor subsidiaries of Chesapeake's senior notes.

During the first quarter 2001, we purchased and subsequently retired $7.3 million of our 8.5% senior notes due 2012 for total consideration of $7.4 million, including accrued interest of $0.2 million and the write-off of $0.1 million of unamortized bond discount.

On March 30, 2001, we issued 1.1 million shares of Chesapeake common stock in exchange for 49.5% of RAM Energy, Inc.'s, outstanding common stock. Our shares were valued at $8.854 each, or $9.9 million in total. We agreed to adjust the consideration for our acquisition of RAM shares by making a cash payment to the selling RAM shareholders equal to the shortfall if they sold the Chesapeake shares they received at a price less than $8.854 per share. In the third quarter of 2001, the RAM shareholders sold all their shares of Chesapeake common stock at prices below this level and we made make-whole cash payments of $3.3 million to them to cover the shortfall. In December 2001, we sold all the RAM shares we owned for minimal consideration. In addition during 2001, we purchased $17.4 million principal amount of RAM's corporate notes for a total purchase price of $15.2 million, including accrued interest of $0.6 million. On December 4, 2001 we purchased certain oil and gas assets owned by RAM located primarily in the Mid-Continent. The consideration for this acquisition was $74.4 million, consisting of $61.7 million of cash, surrender of $11.5 million principal amount of our RAM notes including $0.4 million in accrued interest, and cancellation of a $1.2 million receivable by us from RAM. Subsequent to year-end, we sold the remaining $6.3 million principal amount of RAM notes, which had a carrying value on our books of $3.8 million, for $4.4 million, including accrued interest of $0.2 million.

On April 6, 2001, we issued $800.0 million principal amount of 8.125% senior notes due 2011, all of which were subsequently exchanged for substantially identical notes registered under the Securities Act of 1933. The net proceeds were approximately $780.6 million. During April 2001, we used a portion of the offering proceeds to purchase $140.7 million principal amount of our 9.625% senior notes and $3.0 million principal amount of the 11.125% senior secured notes of Gothic Production Corporation, a Chesapeake subsidiary. On May 7, 2001, we redeemed all $120.0 million principal amount of our 9.125% senior notes, the remaining $359.3 million principal amount of our 9.625% senior notes and the remaining $199.3 million principal amount of Gothic Production Corporation's 11.125% senior secured notes. The purchase and redemption of these notes included payment of aggregate make-whole and redemption premiums of $75.6 million and the write-off of unamortized debt costs and debt issue premiums. The costs associated with the early extinguishment of debt were reflected as a $46.0 million after-tax extraordinary loss in 2001. The refinancing lowered the interest rate and extended the maturity of approximately 74% of our senior notes outstanding at that time.

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of 7% preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

In July 2001, we purchased $22.5 million principal amount of 12% senior secured notes due 2004 issued by Seven Seas Petroleum Inc. and detachable seven-year warrants to purchase approximately 12.6 million shares of Seven Seas common stock at an exercise price of approximately $1.78 per share. The shares issuable upon exercise of the warrants represent approximately 20% of Seven Seas outstanding common stock on a fully diluted basis. Seven Seas common stock is listed for trading on the American Stock Exchange and the common shares underlying our warrants have been registered under the federal securities laws for resale. The 12% senior secured notes held by us and the $22.5 million of notes acquired by other parties are secured by a pledge of substantially all of the assets owned by Seven Seas, including all of the Seven Seas subsidiaries which hold the concessions to the company's oil and gas interests in Colombia.

On September 21, 2001, our board of directors authorized the repurchase of up to $50 million of our common stock, either through direct purchases or put options. We have not made any repurchases or written any put options to date under this program. The consent to the stock repurchase program we obtained under our bank credit facility expires June 30, 2002.

On November 5, 2001, Chesapeake closed a private offering of $250.0 million of 8.375% senior notes due 2008, all of which were exchanged on January 23, 2002 for substantially identical notes registered under the Securities Act of 1933. The net proceeds were approximately $247.7 million. The 8.375% senior notes will be redeemable by us prior to November 1, 2005 by payment of a make-whole premium, and on and after November 1, 2005 at annually declining redemption prices. The 8.375% senior notes are guaranteed by the same subsidiaries that guarantee our other outstanding senior notes and are subject to covenants substantially similar to those contained in the indenture for our 8.125% senior notes.

On November 13, 2001, Chesapeake issued 3.0 million shares of 6.75% cumulative convertible preferred stock, par value $.01 per share and a liquidation preference of $50 per share, in a private offering. The net proceeds from the offering were $145.1 million. Each preferred share is convertible at any time at the option of the holder into 6.4935 shares of our common stock, subject to adjustment. The conversion rate is based on an initial conversion price of $7.70 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 20, 2004 at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price at the time and (2) on or after November 20, 2006 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. Annual cumulative cash dividends of $3.375 per share are payable quarterly on the fifteenth day of each February, May, August and November. We have registered under the Securities Act of 1933 shares of the preferred stock and underlying common stock for resale by the holders.

In private transactions completed in the fourth quarter of 2001 and January 2002, we acquired 7.65% of the outstanding common stock of Canaan Energy Corporation, an oil and gas exploration and production company, for cash consideration totaling $4.0 million, or $12.00 per share. On March 11, 2002, we announced our intention to commence a cash tender offer to acquire Canaan for $12.00 per share of common stock. The $12.00 offer price represents an aggregate purchase price for the common stock on a fully diluted basis of approximately $55.0 million plus the assumption of Canaan's debt, which was approximately $42.0 million as of December 31, 2001. On March 15, 2002, we announced that we would defer commencement of the tender offer based upon the representations of Canaan senior management of their willingness to engage in good faith discussions with us regarding the offer and upon their request that we delay commencement of the tender offer until after the discussions. We may at any time commence or modify our proposed tender offer for Canaan shares or terminate our tender offer plans. If and when the tender offer is commenced, the complete terms and conditions of the offer will be set forth in tender offer materials that we will file with the Securities and Exchange Commission.

In March 2002, we purchased and subsequently retired $13.0 million of our 7.875% senior notes due 2004 for total consideration of $13.7 million, including accrued interest of $0.4 million.

CRITICAL ACCOUNTING POLICIES

Readers of this document 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 three most significant policies are discussed below.

Hedging. From time to time, Chesapeake uses commodity price risk management instruments to hedge our exposure to price fluctuations in oil and natural gas and interest rates. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results of oil and gas hedging transactions are reflected in oil and gas sales to the extent related to our oil and gas production. The changes in fair value of derivative instruments not qualifying for designation as cash flow hedges that occur prior to maturity are initially reported in the consolidated statement of operations as risk management income (loss). All amounts initially recorded in this caption are ultimately reversed within the same caption and included in oil and gas sales over the respective contracts terms.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement 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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. 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. 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. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow hedge are also recognized in earnings through risk management income. See Hedging Activities and Item 7A - Quantitative and Qualitative Disclosures about Market Risk for additional information regarding our hedging activities.

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. Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. As of December 31, 2001, approximately 72% of our present value (discounted at 10%) of estimated future net revenues of proved reserves was evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers reevaluate our reserves on a quarterly basis.

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. 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.

Income Taxes. As part of the process of preparing the consolidated financial statements, we are required to estimate the 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 the net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess the likelihood that the deferred tax assets will be recovered from future taxable income and to the extent we believe that recovery is not likely, we must establish a valuation allowance. 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.

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 this exposure to adverse market changes, we have entered into derivative instruments. All of our derivative instruments have been entered into as hedges of oil and gas price risk and not for speculative purposes.

We utilize derivative instruments to reduce exposure to unfavorable changes in oil and gas prices which are subject to significant and often volatile fluctuations. As of December 31, 2001, our derivative instruments were comprised of swaps, collars, cap-swaps and locked swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production.

Pursuant to SFAS 133, our cap-swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

The estimated fair values of our derivative instruments as of December 31, 2001 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	DECEMBER 31, 2001 ($ IN THOUSANDS)
Derivative assets:	
Fixed-price gas cap-swaps	$ 77,208
Fixed-price gas locked swaps	50,549
Fixed-price gas collars	15,360
Fixed-price gas swaps	6,268
Fixed-price crude oil cap-swaps	5,078
Fixed-price crude oil locked swaps	2,846
Total	$ 157,309

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties. 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, 2001.

Additional information concerning the fair value of our derivative instruments is as follows ($ in thousands):

Fair value of contracts outstanding at January 1, 2001	$ (89,288)
Change in fair value of contracts during period	351,989
Contracts realized or otherwise settled during the period	(105,392)
Fair value of new contracts when entered into during the period	--
Changes in fair values attributable to changes in valuation techniques and assumptions	--
Fair value of contracts outstanding at December 31, 2001	$ 157,309

	FAIR VALUE OF CONTRACTS AT PERIOD-END ($ IN THOUSANDS)				
SOURCE OF FAIR VALUE	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	OVER 5 YEARS	TOTAL
Prices provided by other external sources	$ 132,087	$ 25,222	$ --	$ --	$ 157,309
Prices actively quoted	--	--	--	--	--
Prices based on models and other valuation methods	--	--	--	--	--
Total	$ 132,087	$ 25,222	$ --	$ --	$ 157,309

DISCLOSURES ABOUT EFFECTS OF TRANSACTIONS WITH RELATED PARTIES

Since Chesapeake was founded in 1989, our chief executive officer and chief operating officer have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. As of December 31, 2001, we had accounts receivable from our CEO and COO of $5.0 million and $4.9 million, respectively, representing joint interest billings payable within 90 days. Under their employment agreements, the CEO and COO are permitted to participate in all, or none, of the wells spudded by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to only participate in select 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 a quarter. Their participation is permitted only under the terms outlined in their employment agreements, which, among other things, limit their 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 October 2001, we sold Chesapeake Canada Corporation, a wholly-owned subsidiary, for net proceeds of approximately $143.0 million. Our CEO and COO each received $2.0 million related to their fractional ownership interest in these Canadian assets, which they acquired and paid for pursuant to the terms of their employment agreements. The portion of the proceeds allocated to our CEO and COO was based upon the estimated fair values of the assets sold as determined by management and the independent members of our board of directors using a methodology similar to that used by Chesapeake for acquisitions of assets from disinterested third parties.

During 2001, 2000 and 1999, we paid legal fees of $391,000, $439,000 and

$398,000, respectively, for legal services provided by a law firm of which a director is a member.

RECENTLY ISSUED ACCOUNTING STANDARDS

In June 2001, the Financial Accounting Standards Board issued SFAS Nos. 141 and 142. SFAS No. 141, Business Combinations, requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS No. 142, Goodwill and Other Intangible Assets, changes the accounting for goodwill from an amortization method to an impairment-only approach and will be effective January 2002. We believe that adoption of this new standard will not have an effect on our results of operations or our financial position. In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. We have not yet determined the effect of the adoption of SFAS 143 on our financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. SFAS 144 is effective for fiscal years beginning after December 15, 2002. This statement supersedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of, and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. We believe the future impact of the adoption of SFAS 144 on our financial position or results of operations will not be material.

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, expected future expenses and utilization of net operating loss carryforwards. 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 1 and include:

- the volatility of oil and gas prices,
- our substantial indebtedness,
- the cost and availability of drilling and production services,
- our commodity price risk management activities, including counterparty contract performance risk,
- uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures,
- our ability to replace reserves,
- the availability of capital,
- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- drilling and operating risks,
- our ability to generate future taxable income sufficient to utilize our NOLs before expiration,
- future ownership changes which could result in additional limitations to our NOLs,
- adverse effects of governmental and environmental regulation,
- losses possible from pending or future litigation,
- the strength and financial resources of our competitors, and
- the loss of officers or key employees.

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 and our other reports filed 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

COMMODITY RISK MANAGEMENT ACTIVITY

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of this exposure to adverse market changes, we have entered into derivative instruments. All of our derivative instruments have been entered into as hedges of oil and gas price risk and not for speculative purposes.

We utilize derivative instruments to reduce exposure to unfavorable changes in oil and gas prices which are subject to significant and often volatile fluctuations. As of December 31, 2001, our derivative instruments were comprised of swaps, collars, cap-swaps and locked swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, 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.

- 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, then we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, then no payments are due from either party.

- For cap-swaps, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" on the floating market price, which limits the counterparty's exposure.

- Locked swaps consist of swap positions which have been effectively closed by entering into a counter-swap instrument where we receive the floating price for the hedged commodity and pay a fixed price to the counterparty. At the time we enter into the counter-swap, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133. The net values of both the swap and counter-swap are frozen and shown as derivatives receivable or payable in the consolidated balance sheet.

Pursuant to SFAS 133, our cap-swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity are reported in the statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

The estimated fair values of our derivative instruments as of December 31, 2001 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	DECEMBER 31, 2001 ($ IN THOUSANDS)
Derivative assets:	
Fixed-price gas cap-swaps	$ 77,208
Fixed-price gas locked swaps	50,549
Fixed-price gas collars	15,360
Fixed-price gas swaps	6,268
Fixed-price crude oil cap-swaps	5,078
Fixed-price crude oil locked swaps	2,846
Total	$157,309

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties. 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, 2001.

Risk management income in the consolidated statement of operations for 2001 is comprised of the following:

	2001 ($ IN THOUSANDS)
Risk Management Income:	
Change in fair value of derivatives not qualifying for hedge accounting	$ 106,825
Reclassification of settled contracts	(24,540)
Ineffective portion of derivatives qualifying for hedge accounting	2,504
Total	$ 84,789

Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

The change in fair value of our derivative instruments since January 1, 2001 resulted from a decrease in market prices for natural gas and crude oil. The majority of this change in fair value is reflected in accumulated other comprehensive income, net of deferred income tax effects, in the December 31, 2001 consolidated balance sheet. Derivative assets 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 balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

We expect to transfer approximately $33.7 million of the balance in accumulated other comprehensive income, based upon the market prices at December 31, 2001, to earnings during the next 12 months when the forecasted transactions actually occur. All forecasted transactions hedged as of December 31, 2001 are expected to occur by December 2003.

As of December 31, 2001, we had the following open derivative instruments designed to hedge a portion of our gas production for periods after December 2001:

	SWAPS		CAP-SWAPS			COLLARS		
	VOLUME (mmbtu)	STRIKE PRICE ($ PER mmbtu)	VOLUME (mmbtu)	NYMEX INDEX STRIKE PRICE ($ PER mmbtu)	NYMEX CAPPED LOW STRIKE PRICE ($ PER mmbtu)	VOLUME (mmbtu)	LOW STRIKE PRICE ($ PER mmbtu)	HIGH STRIKE PRICE ($ PER mmbtu)
1st Quarter 2002	17,320,000	2.70	18,900,000	5.32	4.09	1,800,000	4.00	5.75
2nd Quarter 2002	18,820,000	2.75	22,750,000	4.55	3.55	3,640,000	4.00	5.38
3rd Quarter 2002	16,560,000	2.85	23,000,000	4.57	3.57	3,680,000	4.00	5.38
4th Quarter 2002	--	--	18,120,000	4.49	3.49	2,460,000	4.00	5.56
Total 2002	52,700,000	2.76	82,770,000	4.72	3.67	11,580,000	4.00	5.47
1st Quarter 2003	--	--	12,600,000	3.79	2.79	--	--	--
2nd Quarter 2003	--	--	12,740,000	3.42	2.42	--	--	--
3rd Quarter 2003	--	--	12,880,000	3.50	2.50	--	--	--
4th Quarter 2003	--	--	12,880,000	3.69	2.69	--	--	--
Total 2003	--	--	51,100,000	3.60	2.60	--	--	--

The above table does not include locked swaps of 43,510,000 mmbtu for 2002 and 55,340,000 mmbtu for 2003.

Subsequent to December 31, 2001, we settled the gas swaps, gas cap-swaps and gas collars for January, February and March 2002. Gains totaling $45.2 million will be recognized as price adjustments in the first quarter of 2002 and are comprised of $19.1 million for gas swaps, $23.2 million for gas cap-swaps and $2.9 million for gas collars. Any associated gains related to cap-swaps and the ineffective portion of derivatives qualifying for hedge accounting that were recognized during 2001 as risk management income will be reclassified from risk management income to oil and gas sales during 2002.

As of December 31, 2001, we had the following open derivative instruments designed to hedge a portion of our domestic crude oil production for periods after December 2001:

	CAP-SWAPS		
	VOLUME (bbls)	NYMEX INDEX STRIKE PRICE ($ per bbl)	NYMEX CAPPED LOW STRIKE PRICE ($ per bbl)
1st Quarter 2002	270,000	25.64	20.64
2nd Quarter 2002	273,000	25.41	20.41
3rd Quarter 2002	276,000	25.18	20.18
4th Quarter 2002	276,000	24.98	19.98
Total 2002	1,095,000	25.30	20.30

Subsequent to December 31, 2001, we settled the oil cap-swaps for January and February 2002 for gains of $1.0 million for oil swaps and $0.8 million for oil cap-swaps. Any associated gains related to cap-swaps and the ineffectiveness portions of derivatives qualifying for hedge accounting that were recognized during 2001 as risk management income will be reclassified from risk management income to oil and gas sales during 2002.

As of December 31, 2001, we closed certain swap transactions designed to hedge a portion of our domestic oil and natural gas production. We refer to these transactions as locked swaps. The net unrecognized gains resulting from these transactions will be recognized as price adjustments in the months of related production. At December 31, 2001, these amounts are classified as derivative receivables on the consolidated balance sheet. These hedging gains and losses are set forth below:

	LOCKED SWAPS HEDGING GAINS		
	GAS	OIL	TOTAL
	($ IN THOUSANDS)		
1st Quarter 2002	$11,968	$ 1,443	$13,411
2nd Quarter 2002	6,437	1,208	7,645
3rd Quarter 2002	6,231	195	6,426
4th Quarter 2002	7,061	--	7,061
Total 2002	$31,697	$ 2,846	$34,543
1st Quarter 2003	$ 6,633	$ --	$ 6,633
2nd Quarter 2003	3,869	--	3,869
3rd Quarter 2003	4,293	--	4,293
4th Quarter 2003	4,057	--	4,057
Total 2003	$18,852	$ --	$18,852
Grand Total	$50,549	$ 2,846	$53,395

INTEREST RATE RISK

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

	DECEMBER 31, 2001							
	YEARS OF MATURITY							
	2002	2003	2004	2005	2006	THEREAFTER	TOTAL	FAIR VALUE
	($ IN MILLIONS)							
LIABILITIES:								
Long-term debt, including								
current portion -- fixed rate	$ 0.6	$ --	$ 150.0	$ --	$ --	$1,192.6	$1,343.2(1)	$1,343.0
Average interest rate	9.1%	--	7.9%	--	--	8.2%	8.2%	8.2%
Long-term debt -- variable rate	$ --	$ --	$ --	$ --	$ --	$ --	$ --	$ --
Average interest rate	--	--	--	--	--	--	--	--

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(1) This amount does not include the discount of $13.2 million included in

long-tem debt.

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 credit facility. At December 31, 2001, we were not using any interest rate derivative instruments to manage exposure to interest rate changes. 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

CHESAPEAKE ENERGY CORPORATION

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders
of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 8 of the Form 10-K present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at December 31, 2000 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule also 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 financial statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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 1 to the financial statements, in 2001, the Company changed its method of accounting for its hedging activities as a result of adopting the provisions of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities".

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
March 8, 2002

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31, 2000	DECEMBER 31, 2001
	($ IN THOUSANDS)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ --	$ 117,594
Restricted cash	3,500	7,366
Accounts receivable:		
Oil and gas sales	97,062	51,496
Joint interest, net of allowances of $1,085,000 and $947,000, respectively	12,940	17,364
Short-term derivatives	--	34,543
Related parties	4,383	9,896
Other	3,058	14,951
Deferred income tax asset	40,819	--
Short-term derivative instruments	--	97,544
Inventory and other	5,164	10,629
Total Current Assets	166,926	361,383
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	2,590,512	3,546,163
Unevaluated properties	25,685	66,205
Less: accumulated depreciation, depletion and amortization	(1,770,827)	(1,902,587)
	845,370	1,709,781
Other property and equipment	79,898	115,694
Less: accumulated depreciation and amortization	(37,034)	(39,894)
Total Property and Equipment	888,234	1,785,581
OTHER ASSETS:		
Investment in Gothic Energy Corporation	126,434	--
Long-term derivatives receivable	--	18,852
Deferred income tax asset	229,823	67,781
Long-term derivative instruments	--	6,370
Long-term investments	2,000	29,849
Other assets	27,009	16,952
Total Other Assets	385,266	139,804
TOTAL ASSETS	$ 1,440,426	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Notes payable and current maturities of long-term debt	$ 836	$ 602
Accounts payable	62,940	79,945
Accrued interest	17,537	26,316
Other accrued liabilities	45,706	36,998
Revenues and royalties due others	35,682	29,520
Total Current Liabilities	162,701	173,381
LONG-TERM DEBT, NET	944,845	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	7,798	12,696
DEFERRED INCOME TAX LIABILITY	11,850	--
OTHER LIABILITIES	--	3,831
CONTINGENCIES AND COMMITMENTS (NOTE 4)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 10,000,000 shares authorized,		
7% cumulative convertible preferred stock; 624,037 and 0 shares authorized, issued and outstanding at December 31, 2000 and 2001, respectively, entitled in liquidation to $31.2 million and $0 million, respectively	31,202	--
6.75% cumulative convertible preferred stock; 0 and 3,000,000 shares authorized, issued and outstanding at December 31, 2000 and 2001, respectively, entitled in liquidation to $0 and $150 million, respectively	--	150,000
Common Stock, $.01 par value, 350,000,000 shares authorized, 157,819,171 and 169,534,991 shares issued at December 31, 2000 and 2001, respectively	1,578	1,696
Paid-in capital	963,584	1,035,156
Accumulated deficit	(659,286)	(442,974)
Accumulated other comprehensive income (loss), net of tax of $3,191,000 and ($29,000,000), respectively	(3,901)	43,511
Less: treasury stock, at cost; 4,788,747 and 4,792,529 common shares at December 31, 2000 and 2001, respectively	(19,945)	(19,982)
Total Stockholders' Equity	313,232	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,440,426	$ 2,286,768

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
	(IN THOUSANDS, EXCEPT PER SHARE DATA)		
REVENUES:			
Oil and gas sales	$ 280,445	$ 470,170	$ 735,529
Risk management income	--	--	84,789
Oil and gas marketing sales	74,501	157,782	148,733
Total Revenues	354,946	627,952	969,051
OPERATING COSTS:			
Production expenses	46,298	50,085	75,374
Production taxes	13,264	24,840	33,010
General and administrative	13,477	13,177	14,449
Oil and gas marketing expenses	71,533	152,309	144,373
Oil and gas depreciation, depletion and amortization	95,044	101,291	172,902
Depreciation and amortization of other assets	7,810	7,481	8,663
Total Operating Costs	247,426	349,183	448,771
INCOME FROM OPERATIONS	107,520	278,769	520,280
OTHER INCOME (EXPENSE):			
Interest and other income	8,562	3,649	2,877
Interest expense	(81,052)	(86,256)	(98,321)
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)	(72,490)	(82,607)	(81,915)
INCOME BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	35,030	196,162	438,365
PROVISION (BENEFIT) FOR INCOME TAXES	1,764	(259,408)	174,959
INCOME BEFORE EXTRAORDINARY ITEM	33,266	455,570	263,406
EXTRAORDINARY ITEM:			
Loss on early extinguishment of debt, net of applicable income tax of $30,667,000	--	--	(46,000)
NET INCOME	33,266	455,570	217,406
PREFERRED STOCK DIVIDENDS	(16,711)	(8,484)	(2,050)
GAIN ON REDEMPTION OF PREFERRED STOCK	--	6,574	--
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 16,555	$ 453,660	$ 215,356
EARNINGS PER COMMON SHARE:			
EARNINGS PER COMMON SHARE -- BASIC:			
Income before extraordinary item	$ 0.17	$ 3.52	$ 1.61
Extraordinary item	--	--	(0.28)
Net income	$ 0.17	$ 3.52	$ 1.33
EARNINGS PER COMMON SHARE-ASSUMING DILUTION:			
Income before extraordinary item	$ 0.16	$ 3.01	$ 1.51
Extraordinary item	--	--	(0.26)
Net income	$ 0.16	$ 3.01	$ 1.25
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING:			
Basic	97,077	128,993	162,362
Assuming dilution	102,038	151,564	173,981

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEARS ENDED DECEMBER 31, 1999	2000	2001
	($ IN THOUSANDS)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
NET INCOME	$ 33,266	$ 455,570	$ 217,406
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation, depletion and amortization	99,516	105,103	177,543
Risk management income	--	--	(84,789)
Extraordinary loss on early extinguishment of debt	--	--	46,000
Deferred income taxes	1,764	(259,408)	169,498
Impairment of investments	--	250	10,079
Gain on sale of Canadian subsidiary	--	--	(27,000)
Write-off of credit facility costs	--	--	3,392
Amortization of loan costs	3,338	3,669	4,022
Amortization of bond discount	84	84	1,062
Bad debt expense	9	256	69
Gain (loss) on sale of fixed assets and other	(459)	8	68
Equity in losses of equity investees	1,209	131	1,312
Other	--	141	(99)
Cash provided by operating activities before changes in current assets and liabilities	138,727	305,804	518,563
CHANGES IN ASSETS AND LIABILITIES:			
(Increase) decrease in accounts receivable	17,592	(66,706)	34,265
(Increase) decrease in inventory and other current assets	4,357	4,299	929
Increase (decrease) in accounts payable, accrued liabilities and other	(19,171)	64,961	2,454
Increase (decrease) in current and non-current revenues and royalties due others	3,517	6,282	(2,474)
Changes in assets and liabilities	6,295	8,836	35,174
Cash provided by operating activities	145,022	314,640	553,737
CASH FLOWS FROM INVESTING ACTIVITIES:			
Exploration and development of oil and gas properties	(153,268)	(188,778)	(420,969)
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(49,893)	(78,910)	(316,743)
Sale of Canadian subsidiary	--	--	142,906
Divestitures of oil and gas properties	45,635	1,529	1,432
Sale of non-oil and gas assets	5,530	1,069	3,204
Additions to buildings and other fixed assets	(1,182)	(13,427)	(24,853)
Additions to drilling rig equipment	--	--	(14,145)
Additions to long-term investments	(730)	(9,937)	(40,239)
Investment in Gothic Energy Corporation	--	(36,693)	--
Other	--	(82)	(698)
Cash used in investing activities	(153,908)	(325,229)	(670,105)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	116,500	244,000	433,500
Payments on long-term borrowings	(98,000)	(262,500)	(458,500)
Cash received from issuance of senior notes	--	--	1,028,275
Cash paid for financing costs of credit facilities	(5,865)	(4,807)	(6,611)
Cash paid to purchase senior notes	--	--	(830,382)
Cash paid for redemption premium on senior notes	--	--	(75,639)
Cash paid for preferred stock dividend	--	(4,645)	(1,092)
Proceeds from issuance of preferred stock	--	--	145,086
Purchase of treasury stock and preferred stock	(53)	--	(10)
Cash paid in connection with issuance of common stock for preferred stock	--	(8,269)	--
Cash received (paid) in settlements of make-whole provisions	--	7,083	(3,336)
Cash received from exercise of stock options	520	1,398	3,216
Cash provided by (used in) financing activities	13,102	(27,740)	234,507
EFFECT OF EXCHANGE RATE CHANGES ON CASH	4,922	(329)	(545)
Net increase (decrease) in cash and cash equivalents	9,138	(38,658)	117,594
Cash and cash equivalents, beginning of period	29,520	38,658	--
Cash and cash equivalents, end of period	$ 38,658	$ --	$ 117,594

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,		
	1999	2000	2001
	($ IN THOUSANDS)		
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
CASH PAYMENTS FOR:			
Interest, net of capitalized interest	$ 80,684	$ 85,401	$ 97,832
Income taxes	$ --	$ --	$ 5,461
DETAILS OF ACQUISITION OF GOTHIC ENERGY CORPORATION:			
Fair value of properties acquired	$ --	$ --	$ 371,371
Fair value of notes acquired	$ --	$ 115,545	$ --
Cash consideration	$ --	$ (28,715)	$ --
Stock issued (13,553,276 shares and 3,989,813 shares)	$ --	$ (86,830)	$ (28,000)
Gothic preferred and common stock held by Chesapeake	$ --	$ --	$ (10,000)
Debt assumed	$ --	$ --	$(331,255)
Acquisition costs and other	$ --	$ --	$ (2,116)

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

In 2001, Chesapeake completed the acquisition of Gothic Energy Corporation. We issued 3,989,813 shares of Chesapeake common stock to Gothic shareholders (other than Chesapeake).

In 2001, we issued 1,117,216 shares of Chesapeake common stock in exchange for 49.5% of RAM Energy, Inc.'s outstanding common stock. Chesapeake shares were valued at $8.854 per share. Subsequently, we made a make-whole payment to the former RAM shareholders of $3.3 million.

In 2001, Chesapeake purchased certain oil and gas assets from RAM Energy, Inc. for a total consideration of $74.4 million, consisting of $61.7 million of cash, surrender of $11.5 million principal amount of our RAM notes including $0.4 million in accrued interest, and cancellation of a $1.2 million receivable by us from RAM.

During 2000, Chesapeake engaged in unsolicited transactions in which a total of 43.4 million shares of Chesapeake common stock, plus a cash payment of $8.3 million, were exchanged for 3,972,363 shares of Chesapeake preferred stock.

During 2000, Chesapeake Energy Marketing, Inc. purchased 99.8% of Gothic Energy Corporation's $104 million 14.125% Series B senior secured discount notes for total consideration of $80.8 million, comprised of $17.2 million in cash and $63.6 million of Chesapeake common stock (8,875,775 shares valued at $7.16 per share), as adjusted for make-whole provisions. Through the make-whole provisions, Chesapeake Energy Marketing, Inc. received $6.1 million in cash and $7.2 million of Chesapeake common stock (982,562 shares).

In 2000, Chesapeake purchased $31.6 million of the $235 million of 11.125% senior secured notes issued by Gothic Production Corporation for total consideration of $34.8 million, comprised of $11.5 million in cash and $23.3 million of Chesapeake common stock (3,694,939 shares valued at $6.30 per share), as adjusted for make-whole provisions. Through the make-whole provisions, Chesapeake received $1.0 million in cash.

In 1999, the chief executive officer and chief operating officer of Chesapeake tendered to Chesapeake Energy Marketing, Inc. 2,320,107 shares of Chesapeake common stock in full satisfaction of two notes payable to CEMI with a combined outstanding balance of $7.6 million. At the time, Chesapeake's stock price was $3.29 per share and Chesapeake received full value for the satisfaction of the two notes.

During 1999, we issued a $2.2 million note payable as consideration for the acquisition of certain oil and gas properties.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
	($ IN THOUSANDS)		
PREFERRED STOCK:			
Balance, beginning of period	$ 230,000	$ 229,820	$ 31,202
Exchange of common stock and cash for 3,972,363 shares of preferred stock	--	(198,618)	--
Exchange of common stock for 3,600 shares of preferred stock	(180)	--	--
Exchange of common stock for 624,037 shares of preferred stock	--	--	(31,202)
Issuance of preferred stock	--	--	150,000
Balance, end of period	229,820	31,202	150,000
COMMON STOCK:			
Balance, beginning of period	1,052	1,059	1,578
Exercise of stock options and warrants	6	20	21
Issuance of 3,989,813 shares of common stock to Gothic shareholders	--	--	40
Issuance of 1,117,216 shares of common stock to RAM Energy, Inc. shareholders	--	--	11
Exchange of 36,366,915 shares of common stock for preferred stock	--	363	--
Issuance of 13,553,276 shares of common stock to acquire Gothic notes	--	136	--
Exchange of 4,487,410 shares of common stock for preferred stock	--	--	45
Other	1	--	1
Balance, end of period	1,059	1,578	1,696
PAID-IN CAPITAL:			
Balance, beginning of period	682,263	682,905	963,584
Exercise of stock options and warrants	514	1,377	3,188
Issuance of common stock to acquire Gothic notes	--	93,885	--
Issuance of common stock to acquire RAM Energy, Inc. common stock	--	--	9,881
Issuance of common stock to acquire Gothic Energy Corporation	--	--	29,389
Offering expenses and other	1	--	(4,891)
Exchange of 36,366,915 shares of common stock for preferred stock	127	187,069	--
Exchange of 4,487,410 shares of common stock for preferred stock	--	--	31,157
Exchange of 7,050,000 shares of treasury stock for preferred stock	--	(5,640)	--
Make-whole payments on common stock issued to RAM Energy, Inc. shareholders	--	--	(3,336)
Compensation related to stock options	--	238	800
Tax benefit from exercise of stock options	--	3,750	5,384
Balance, end of period	682,905	963,584	1,035,156
ACCUMULATED DEFICIT:			
Balance, beginning of period	(1,127,195)	(1,093,929)	(659,286)
Net income	33,266	455,570	217,406
Dividends on preferred stock	--	(4,645)	(1,094)
Fair value of common stock exchanged in excess of book value of preferred stock	--	(8,013)	--
Cash paid in connection with issuance of common stock for preferred stock	--	(8,269)	--
Balance, end of period	(1,093,929)	(659,286)	(442,974)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance, beginning of period	(4,726)	196	(3,901)
Foreign currency translation adjustments	4,922	(4,097)	(3,551)
Transfer of translation adjustments related to sale of Canadian subsidiary	--	--	7,452
Gain on hedging activity	--	--	43,511
Balance, end of period	196	(3,901)	43,511
TREASURY STOCK -- COMMON:			
Balance, beginning of period	(29,962)	(37,595)	(19,945)
Settlement of notes receivable for 2,320,107 shares of common stock from related parties	(7,633)	--	--
Exercised options	--	--	(37)
Exchange of 7,050,000 shares of treasury stock for preferred stock	--	24,841	--
Receipt of 982,562 shares of common stock from previous Gothic note holders in settlement of make-whole provision	--	(7,191)	--
Balance, end of period	(37,595)	(19,945)	(19,982)
TOTAL STOCKHOLDERS' EQUITY (DEFICIT)	$ (217,544)	$ 313,232	$ 767,407

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
	($ IN THOUSANDS)		
Net income	$ 33,266	$ 455,570	$ 217,406
Other comprehensive income (loss), net of income tax:			
Foreign currency translation adjustments	4,922	(4,097)	(3,551)
Transfer of translation adjustments related to sale of Canadian subsidiary	--	--	7,452
Cumulative effect of accounting change for financial derivatives	--	--	(53,573)
Change in fair value of derivative instruments	--	--	147,210
Reclassification of settled contracts	--	--	(48,623)
Ineffectiveness portion of derivatives qualifying for hedge accounting	--	--	(1,503)
Comprehensive income	$ 38,188	$ 451,473	$ 264,818

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Company

Chesapeake Energy Corporation 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 and New Mexico.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation 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 debt instruments with maturities of three months or less at date of purchase to be cash equivalents.

Inventory

Inventory, which is included in other current assets, consists primarily of 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 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, 2001, approximately 72% of our present value (discounted at 10%) of estimated future net revenues of proved reserves was evaluated by independent petroleum engineers, with the balance evaluated by our internal reservoir engineers. In addition, our internal engineers evaluate all properties quarterly. The average composite rates used for depreciation, depletion and amortization were $1.07 ($1.08 in U.S. and $0.90 in Canada) per equivalent mcf in 2001, $0.75 ($0.76 in U.S. and $0.71 in Canada) per equivalent mcf in 2000, and $0.71 ($0.73 in U.S. and $0.52 in Canada) per equivalent mcf in 1999.

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. 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.

Other Property and Equipment

Other property and equipment consists primarily of gas gathering and processing facilities, drilling rigs, vehicles, land, office buildings and equipment, and software. Major renewals and betterments are capitalized while the costs of repairs and maintenance are charged to expense as incurred. The costs of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from the accounts, and the resulting gain or loss is reflected in operations. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from five to seven years.

Capitalized Interest

During 2001, 2000 and 1999, interest of approximately $4.7 million, $2.4 million and $3.5 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.

Income Taxes

Chesapeake has adopted Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. SFAS 109 requires deferred tax liabilities or assets to be recognized for the anticipated future tax effects of temporary differences that arise as a result of the differences in the carrying amounts and the tax bases of assets and liabilities.

Net Income (Loss) 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 year ended December 31, 2001, outstanding warrants to purchase 1.1 million shares of common stock at a weighted average exercise price of $12.61 were antidilutive because the exercise prices of the warrants were greater than the average market price of the common stock.

- For the years ended December 31, 2001, 2000 and 1999, outstanding options to purchase 0.3 million, 1.1 million, and 1.3 million shares of common stock at a weighted average exercise price of $15.54, $8.73, and $7.14, 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, 1999, the assumed conversion of the outstanding 7% preferred stock (convertible into 33 million common shares) was not included as the effect was antidilutive.

A reconciliation for the years ended December 31, 1999, 2000 and 2001 is as follows:

	INCOME (NUMERATOR)	SHARES (DENOMINATOR)	PER SHARE AMOUNT
	(IN THOUSANDS, EXCEPT PER SHARE DATA)		
FOR THE YEAR ENDED DECEMBER 31, 1999:			
BASIC EPS			
Income available to common stockholders	$ 16,555	97,077	$ 0.17
EFFECT OF DILUTIVE SECURITIES			
Employee stock options	--	4,961	
DILUTED EPS			
Income available to common stockholders and assumed conversions	$ 16,555	102,038	$ 0.16
FOR THE YEAR ENDED DECEMBER 31, 2000:			
BASIC EPS			
Income available to common stockholders	$ 453,660	128,993	$ 3.52
EFFECT OF DILUTIVE SECURITIES			
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:			
Common shares assumed issued	--	11,440	
Preferred stock dividends	8,484	--	
Gain on redemption of preferred stock	(6,574)	--	
Assumed conversion of 624,037 shares of 7% preferred stock at beginning of period	--	4,489	
Employee stock options	--	6,642	
DILUTED EPS			
Income available to common stockholders and assumed conversions	$ 455,570	151,564	$ 3.01
FOR THE YEAR ENDED DECEMBER 31, 2001:			
BASIC EPS			
Income available to common stockholders	$ 215,356	162,362	$ 1.33
EFFECT OF DILUTIVE SECURITIES			
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:			
Common shares assumed issued for 6.75% preferred stock		2,989	
Common shares assumed issued prior to conversion for 7% preferred stock		1,464	
Preferred stock dividends	2,050	--	
Employee stock options	--	7,160	
Warrants assumed in Gothic acquisition	--	6	
DILUTED EPS			
Income available to common stockholders and assumed conversions	$ 217,406	173,981	$ 1.25

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of 7% preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

On November 13, 2001, we issued 3.0 million shares of 6.75% cumulative convertible preferred stock, par value $0.01 per share and liquidation preference $50 per share, in a private offering. We subsequently registered under the Securities Act of 1933 shares of the preferred stock and underlying common stock for resale by the holders.

During the year ended December 31, 2000, Chesapeake engaged in a number of unsolicited stock transactions with institutional investors. A total of 43.4 million shares of common stock, plus a cash payment of $8.3 million, were exchanged for 3,972,363 shares of 7% preferred stock. These transactions reduced (i) the number of preferred shares from 4.6 million to 0.6 million, (ii) the liquidation value of the preferred stock from $229.8 million to $31.2 million, and (iii) dividends in arrears by $22.9 million. A gain on redemption of all preferred shares exchanged during 2000 of $6.6 million is reflected in net income available to common shareholders in determining basic earnings per share. All preferred shares acquired in these transactions were canceled and retired and restored to the status of authorized but unissued shares of undesignated preferred stock. The gain represented the excess of (i) the liquidation value of the preferred shares that were retired plus dividends in arrears which had reduced prior EPS over (ii) the market value of the common stock issued and cash paid in exchange for the preferred shares.

Gas Imbalances -- Revenue Recognition

Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. 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. A liability is recognized only to the extent that we have an imbalance in excess of the remaining gas reserves on the underlying properties.

Hedging

Chesapeake periodically uses commodity price risk management instruments to hedge our exposure to price fluctuations in oil and natural gas transactions and interest rates. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results of oil and gas hedging transactions are reflected in oil and gas sales to the extent related to our oil and gas production. The changes in fair value of derivative instruments not qualifying for designation as cash flow hedges that occur prior to maturity are initially reported in the statement of operations as risk management income (loss). All amounts recorded in this caption are ultimately reversed within the same caption and included in oil and gas sales over the respective contract terms.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement 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. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results of the hedged item in the consolidated statement of operations. 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. 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. Any change in fair value resulting from ineffectiveness, as defined by SFAS 133, is recognized immediately in earnings. Changes in fair value of contracts that do not meet the SFAS 133 definition of a cash flow hedge are also recognized in earnings through risk management income.

Adoption of SFAS 133 at January 1, 2001 resulted in the recognition of $9.3 million of current derivative assets and $98.6 million in current derivative liabilities. The cumulative effect of the accounting change decreased accumulated other comprehensive income by $53.6 million, net of income tax, but did not have an effect on our net income or earnings per share amounts.

Debt Issue Costs

Included in other assets are costs associated with the issuance of our senior notes and amendments to our revolving bank credit facility. The remaining unamortized debt issue costs at December 31, 2001 and 2000 totaled $16.6 million and $15.8 million, respectively, and are being amortized over the life of the senior notes or revolving credit facility.

Currency Translation

The results of operations for non-U.S. subsidiaries are translated from local currencies into U.S. dollars using average exchange rates during each period; assets and liabilities are translated using exchange rates at the end of each period. Adjustments resulting from the translation process are reported in a separate component of stockholders' equity, and are not included in the determination of the results of operations. In October 2001, we sold our Canadian subsidiary. As a result, all translation adjustments related to our investment in this subsidiary were reclassified in the fourth quarter of 2001.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 1999 and 2000 to conform to the presentation used for the 2001 consolidated financial statements.

2. SENIOR NOTES

On November 5, 2001, Chesapeake closed a private offering of $250.0 million of 8.375% senior notes due 2008, all of which were exchanged on January 23, 2002 for substantially identical notes registered under the Securities Act of 1933. The 8.375% senior notes will be redeemable by us prior to November 1, 2005 by payment of a call or redemption premium, and on and after November 1, 2005 at annually declining redemption prices. The 8.375%

senior notes are guaranteed by the same subsidiaries that guarantee our other outstanding senior notes and are subject to covenants substantially similar to those contained in the indenture for our 8.125% senior notes.

On April 6, 2001, we issued $800.0 million principal amount of 8.125% senior notes due 2011, substantially all of which were exchanged on July 12, 2001 for substantially identical notes registered under the Securities Act of 1933. During April 2001, we used a portion of the offering proceeds to purchase $140.7 million principal amount of our 9.625% senior notes and $3.0 million principal amount of the 11.125% senior secured notes of Gothic Production Corporation, a Chesapeake subsidiary. On May 7, 2001, we redeemed all $120.0 million principal amount of our 9.125% senior notes, the remaining $359.3 million principal amount of our 9.625% senior notes and the remaining $199.3 million principal amount of Gothic Production Corporation's 11.125% senior secured notes. The purchase and redemption of these notes included payment of aggregate make-whole and redemption premiums of $75.6 million and the write-off of unamortized debt costs and debt issue premiums. The costs associated with the early extinguishment of debt are reflected as a $46.0 million after-tax extraordinary loss in 2001.

On January 16, 2001, we acquired Gothic Energy Corporation and assumed its note obligations. At that date, there was outstanding $203.3 million principal amount of 11.125% senior secured notes due 2005 which had been issued by Gothic Production Corporation and guaranteed by Gothic Energy Corporation, its parent. In February 2001, we purchased $1.0 million principal amount of these notes tendered pursuant to a change-of-control offer at a purchase price of 101%. In April 2001, we purchased $3.0 million of these notes for total consideration of $3.5 million, including $0.1 million in interest and $0.4 million in premium. On May 7, 2001, we redeemed the remaining notes ($199.3 million principal amount) for total consideration of $222.5 million, including $0.4 million in interest and $22.8 million in redemption premium.

On April 22, 1998, we issued $500.0 million principal amount of 9.625% senior notes due 2005. In April 2001, we purchased $140.7 million of these notes for total consideration of $160.2 million, including a $13.6 million premium and interest of $5.9 million. On May 7, 2001, we redeemed the remaining notes, $359.3 million principal amount, for total consideration of $393.3 million, including $0.6 million of interest and $33.4 million of redemption premium.

On March 17, 1997, we issued $150.0 million principal amount of 7.875% senior notes due 2004. The 7.875% senior notes are redeemable at our option at any time prior to March 15, 2004 at the make-whole prices determined in accordance with the indenture.

Also on March 17, 1997, we issued $150.0 million principal amount of 8.5% senior notes due 2012. The 8.5% senior notes are redeemable at our option at any time prior to March 15, 2004 at the make-whole prices determined in accordance with the indenture and, on or after March 15, 2004, at the redemption prices set forth in the indenture. During the quarter ended March 31, 2001, Chesapeake purchased and subsequently retired $7.3 million of these notes for total consideration of $7.4 million, including accrued interest of $0.2 million and the write-off of $0.1 million of unamortized bond discount.

On April 9, 1996, we issued $120.0 million principal amount of 9.125% senior notes due 2006. On May 7, 2001, we redeemed these notes for total consideration of $126.1 million, including $0.7 million in interest and $5.4 million of redemption premium.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under the 8.375% senior notes, the 8.125% senior notes, the 7.875% senior notes and the 8.5% senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by each of our "restricted subsidiaries" (as defined in the respective indentures governing these notes) (collectively, the "guarantor subsidiaries"). Each guarantor subsidiary is a direct or indirect wholly-owned subsidiary.

The senior note indentures contain covenants limiting us and the guarantor subsidiaries with respect to asset sales; restricted payments; the incurrence of additional indebtedness and the issuance of preferred stock; liens; sale and leaseback transactions; lines of business; dividend and other payment restrictions affecting guarantor subsidiaries; mergers or consolidations; and transactions with affiliates.

The senior note indentures also limit our ability to make restricted payments (as defined), including the payment of cash dividends, unless the debt incurrence and other tests are met. From December 31, 1998 through March 31, 2000, we were unable to meet the requirements to incur additional unsecured indebtedness, and consequently were restricted from paying cash dividends on our 7% cumulative convertible preferred stock. On September 22, 2000, we declared a regular quarterly dividend and a special dividend equal to all unpaid dividends on our preferred stock, both payable November 1, 2000 to shareholders of record on October 16, 2000. A total combined dividend of $7.444 per outstanding preferred share was paid November 1, 2000.

Set forth below are condensed consolidating financial statements of the guarantor subsidiaries and our subsidiaries which are not guarantors of the senior notes. Chesapeake Energy Marketing, Inc. was a non-guarantor subsidiary for all periods presented. All of our other wholly-owned subsidiaries were guarantor subsidiaries during all periods presented.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2000
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (19,868)	$ 7,200	$ 12,668	$ --	$ --
Restricted cash	3,500	--	--	--	3,500
Accounts receivable	91,903	46,903	--	(21,363)	117,443
Deferred income tax asset	--	--	40,819	--	40,819
Inventory and other	5,037	127	--	--	5,164
Total Current Assets	80,572	54,230	53,487	(21,363)	166,926
PROPERTY AND EQUIPMENT:					
Oil and gas properties	2,590,512	--	--	--	2,590,512
Unevaluated leasehold	25,685	--	--	--	25,685
Other property and equipment	30,670	23,246	25,982	--	79,898
Less: accumulated depreciation, depletion and amortization	(1,787,314)	(18,153)	(2,394)	--	(1,807,861)
Net Property and Equipment	859,553	5,093	23,588	--	888,234
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	--	--	(612,832)	612,832	--
Investment in Gothic Energy Corporation	--	9,732	116,702	--	126,434
Deferred income tax asset	--	--	229,823	--	229,823
Long-tem investments	--	--	2,000	--	2,000
Other assets	9,890	418	87,516	(70,815)	27,009
Total Other Assets	9,890	10,150	(176,791)	542,017	385,266
TOTAL ASSETS	$ 950,015	$ 69,473	$ (99,716)	$ 520,654	$ 1,440,426
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 836	$ --	$ --	$ --	$ 836
Accounts payable and other current liabilities	118,620	49,613	19,090	(25,458)	161,865
Total Current Liabilities	119,456	49,613	19,090	(25,458)	162,701
LONG-TERM DEBT	92,321	--	919,244	(66,720)	944,845
REVENUES AND ROYALTIES DUE OTHERS	7,798	--	--	--	7,798
DEFERRED INCOME TAX LIABILITY	11,850	--	--	--	11,850
INTERCOMPANY PAYABLES	1,351,144	138	(1,351,282)	--	--
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	26	1	1,569	(18)	1,578
Other	(632,580)	19,721	311,663	612,850	311,654
Total Stockholders' Equity	(632,554)	19,722	313,232	612,832	313,232
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 950,015	$ 69,473	$ (99,716)	$ 520,654	$ 1,440,426

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2001
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (7,905)	$ 19,714	$ 113,151	$ --	$ 124,960
Accounts receivable	113,493	30,380	2,715	(18,338)	128,250
Short-term derivative instruments	97,544	--	--	--	97,544
Inventory and other	10,208	421	--	--	10,629
Total Current Assets	213,340	50,515	115,866	(18,338)	361,383
PROPERTY AND EQUIPMENT:					
Oil and gas properties	3,546,163	--	--	--	3,546,163
Unevaluated leasehold	66,205	--	--	--	66,205
Other property and equipment	53,681	23,537	38,476	--	115,694
Less: accumulated depreciation, depletion and amortization	(1,920,613)	(18,668)	(3,200)	--	(1,942,481)
Net Property and Equipment	1,745,436	4,869	35,276	--	1,785,581
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances	--	--	(21,054)	21,054	--
Deferred income tax asset	(218,596)	(1,376)	287,753	--	67,781
Long-term derivative instruments	25,222	--	--	--	25,222
Long-term investments	--	--	29,849	--	29,849
Other assets	5,589	334	11,050	(21)	16,952
Total Other Assets	(187,785)	(1,042)	307,598	21,033	139,804
TOTAL ASSETS	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)					
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 602	$ --	$ --	$ --	$ 602
Accounts payable and other current liabilities	127,967	36,755	26,338	(18,281)	172,779
Total Current Liabilities	128,569	36,755	26,338	(18,281)	173,381
LONG-TERM DEBT	--	--	1,329,453	--	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	12,696	--	--	--	12,696
OTHER LIABILITIES	3,831	--	--	--	3,831
INTERCOMPANY PAYABLES	1,664,517	19	(1,664,458)	(78)	--
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	66	1	1,686	(57)	1,696
Other	(38,688)	17,567	765,721	21,111	765,711
Total Stockholders' Equity	(38,622)	17,568	767,407	21,054	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,770,991	$ 54,342	$ 458,740	$ 2,695	$ 2,286,768

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1999:					
REVENUES:					
Oil and gas sales	$ 280,445	$ --	$ --	$ --	$ 280,445
Oil and gas marketing sales	--	193,900	--	(119,399)	74,501
Total Revenues	280,445	193,900	--	(119,399)	354,946
OPERATING COSTS:					
Production expenses and taxes	59,158	404	--	--	59,562
General and administrative	12,143	1,251	83	--	13,477
Oil and gas marketing expenses	--	190,932	--	(119,399)	71,533
Oil and gas depreciation, depletion and amortization	94,649	395	--	--	95,044
Other depreciation and amortization	4,474	80	3,256	--	7,810
Total Operating Costs	170,424	193,062	3,339	(119,399)	247,426
INCOME (LOSS) FROM OPERATIONS	110,021	838	(3,339)	--	107,520
OTHER INCOME (EXPENSE):					
Interest and other income	3,257	4,823	84,120	(83,638)	8,562
Interest expense	(82,852)	(96)	(81,742)	83,638	(81,052)
Equity in net earnings of subsidiaries	--	--	34,227	(34,227)	--
	(79,595)	4,727	36,605	(34,227)	(72,490)
INCOME (LOSS) BEFORE INCOME TAXES	30,426	5,565	33,266	(34,227)	35,030
INCOME TAX EXPENSE	1,764	--	--	--	1,764
NET INCOME (LOSS)	$ 28,662	$ 5,565	$ 33,266	$ (34,227)	$ 33,266

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 2000:					
REVENUES:					
Oil and gas sales	$ 469,823	$ 347	$ --	$ --	$ 470,170
Oil and gas marketing sales	--	361,023	--	(203,241)	157,782
Total Revenues	469,823	361,370	--	(203,241)	627,952
OPERATING COSTS:					
Production expenses and taxes	74,845	80	--	--	74,925
General and administrative	11,635	1,218	324	--	13,177
Oil and gas marketing expenses	--	355,550	--	(203,241)	152,309
Oil and gas depreciation, depletion and amortization	101,190	101	--	--	101,291
Other depreciation and amortization	4,082	80	3,319	--	7,481
Total Operating Costs	191,752	357,029	3,643	(203,241)	349,183
INCOME (LOSS) FROM OPERATIONS	278,071	4,341	(3,643)	--	278,769
OTHER INCOME (EXPENSE):					
Interest and other income	2,736	883	87,910	(87,880)	3,649
Interest expense	(90,170)	(35)	(83,931)	87,880	(86,256)
Equity in net earnings of subsidiaries	--	--	190,234	(190,234)	--
	(87,434)	848	194,213	(190,234)	(82,607)
INCOME (LOSS) BEFORE INCOME TAXES	190,637	5,189	190,570	(190,234)	196,162
INCOME TAX EXPENSE (BENEFIT)	5,592	--	(265,000)	--	(259,408)
NET INCOME (LOSS)	$ 185,045	$ 5,189	$ 455,570	$(190,234)	$ 455,570

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 2001:					
REVENUES:					
Oil and gas sales	$ 735,529	$ --	$ --	$ --	$ 735,529
Risk management income	84,789	--	--	--	84,789
Oil and gas marketing sales	--	419,279	--	(270,546)	148,733
Total Revenues	820,318	419,279	--	(270,546)	969,051
OPERATING COSTS:					
Production expenses and taxes	108,384	--	--	--	108,384
General and administrative	12,201	1,311	937	--	14,449
Oil and gas marketing expenses	--	414,919	--	(270,546)	144,373
Oil and gas depreciation, depletion and amortization	172,902	--	--	--	172,902
Other depreciation and amortization	6,035	80	2,548	--	8,663
Total Operating Costs	299,522	416,310	3,485	(270,546)	448,771
INCOME (LOSS) FROM OPERATIONS	520,796	2,969	(3,485)	--	520,280
OTHER INCOME (EXPENSE):					
Interest and other income	(130)	473	96,665	(94,131)	2,877
Interest expense	(100,531)	(2)	(91,919)	94,131	(98,321)
Impairments of investments in securities	(8,579)	--	(1,500)	--	(10,079)
Gain on sale of Canadian subsidiary	--	--	27,000	--	27,000
Gothic standby credit facility costs	--	--	(3,392)	--	(3,392)
Equity in net earnings of subsidiaries	--	--	239,968	(239,968)	--
	(109,240)	471	266,822	(239,968)	(81,915)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	411,556	3,440	263,337	(239,968)	438,365
INCOME TAX EXPENSE	165,481	1,376	8,102	--	174,959
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	246,075	2,064	255,235	(239,968)	263,406
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(8,171)	--	(37,829)	--	(46,000)
NET INCOME (LOSS)	$ 237,904	$ 2,064	$ 217,406	$(239,968)	$ 217,406

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1999:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 135,303	$ 7,193	$ 36,753	$ (34,227)	$ 145,022
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(159,888)	2,362	--	--	(157,526)
Proceeds from sale of assets	2,082	3,448	--	--	5,530
Other investments	(480)	(250)	--	--	(730)
Other additions	7	(72)	(1,117)	--	(1,182)
Cash (used in) provided by investing activities	(158,279)	5,488	(1,117)	--	(153,908)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	116,500	--	--	--	116,500
Payments on long-term borrowings	(98,000)	--	--	--	(98,000)
Additions to deferred charges	(5,784)	--	(81)	--	(5,865)
Cash paid for purchase of preferred stock	--	(53)	--	--	(53)
Exercise of stock options	--	--	520	--	520
Intercompany advances, net	15,501	781	(50,509)	34,227	--
Cash provided by (used in) financing activities	28,217	728	(50,070)	34,227	13,102
EFFECT OF EXCHANGE RATE CHANGES ON CASH	4,922	--	--	--	4,922
Net increase (decrease) in cash and cash equivalents	10,163	13,409	(14,434)	--	9,138
Cash, beginning of period	(17,319)	7,000	39,839	--	29,520
Cash, end of period	$ (7,156)	$ 20,409	$ 25,405	$ --	$ 38,658

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 2000:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 320,002	$ (9,627)	$ 194,499	$(190,234)	$ 314,640
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(267,674)	1,515	--	--	(266,159)
Proceeds from sale of assets	782	16	271	--	1,069
Other investments	(8,019)	--	(2,000)	--	(10,019)
Investment in Gothic Energy Corporation	--	(33,076)	(3,617)	--	(36,693)
Other additions	(2,540)	(2,740)	(8,147)	--	(13,427)
Cash (used in) provided by investing activities	(277,451)	(34,285)	(13,493)	--	(325,229)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	244,000	--	--	--	244,000
Payments on long-term borrowings	(262,500)	--	--	--	(262,500)
Additions to deferred charges	(1,913)	--	(2,894)	--	(4,807)
Cash paid for redemption of preferred stock	--	--	(8,269)	--	(8,269)
Cash received on make whole provision	--	6,109	974	--	7,083
Cash dividends paid on preferred stock	--	--	(4,645)	--	(4,645)
Exercise of stock options	--	--	1,398	--	1,398
Intercompany advances, net	(34,521)	24,594	(180,307)	190,234	--
Cash provided by (used in) financing activities	(54,934)	30,703	(193,743)	190,234	(27,740)
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(329)	--	--	--	(329)
Net increase (decrease) in cash and cash equivalents	(12,712)	(13,209)	(12,737)	--	(38,658)
Cash, beginning of period	(7,156)	20,409	25,405	--	38,658
Cash, end of period	$ (19,868)	$ 7,200	$ 12,668	$ --	$ --

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 2001:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 526,589	$ 22,484	$ 244,632	$ (239,968)	$ 553,737
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(736,280)	--	142,906	--	(593,374)
Proceeds from sale of assets	3,204	--	--	--	3,204
Additions to other property and equipment	(26,212)	(292)	(12,494)	--	(38,998)
Other investments	--	--	(40,239)	--	(40,239)
Other additions	(825)	127	--	--	(698)
Cash (used in) provided by investing activities	(760,113)	(165)	90,173	--	(670,105)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	433,500	--	--	--	433,500
Payments on long-term borrowings	(458,500)	--	--	--	(458,500)
Cash received on issuance of senior notes	--	--	1,028,275	--	1,028,275
Additions to deferred charges	(5,984)	--	(627)	--	(6,611)
Cash paid to redeem senior notes	--	--	(906,021)	--	(906,021)
Cash received on issuance of preferred stock	--	--	145,086	--	145,086
Cash paid for purchase of preferred stock	--	--	(10)	--	(10)
Cash paid on make whole provision	--	--	(3,336)	--	(3,336)
Cash dividends paid on preferred stock	--	--	(1,092)	--	(1,092)
Exercise of stock options	--	--	3,216	--	3,216
Intercompany advances, net	273,608	(9,805)	(503,771)	239,968	--
Cash provided by (used in) financing activities	242,624	(9,805)	(238,280)	239,968	234,507
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(545)	--	--	--	(545)
Net increase in cash and cash equivalents	8,555	12,514	96,525	--	117,594
Cash, beginning of period	(19,868)	7,200	12,668	--	--
Cash, end of period	$ (11,313)	$ 19,714	$ 109,193	$ --	$ 117,594

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1999:					
Net income (loss)	$ 28,662	$ 5,565	$ 33,266	$ (34,227)	$ 33,266
Other comprehensive income --					
Foreign currency translation adjustments	4,922	--	--	--	4,922
Equity in net other comprehensive income (loss) of subsidiaries	--	--	4,922	(4,922)	--
Comprehensive income (loss)	$ 33,584	$ 5,565	$ 38,188	$ (39,149)	$ 38,188
FOR THE YEAR ENDED DECEMBER 31, 2000:					
Net income (loss)	$ 185,045	$ 5,189	$ 455,570	$(190,234)	$ 455,570
Other comprehensive income (loss) --					
Foreign currency translation adjustments	(4,097)	--	--	--	(4,097)
Equity in net other comprehensive income (loss) of subsidiaries	--	--	(4,097)	4,097	--
Comprehensive income (loss)	$ 180,948	$ 5,189	$ 451,473	$(186,137)	$ 451,473
FOR THE YEAR ENDED DECEMBER 31, 2001:					
Net income (loss)	$ 237,904	$ 2,064	$ 217,406	$(239,968)	$ 217,406
Other comprehensive income (loss)-					
Foreign currency translation adjustments	(3,551)	--	--	--	(3,551)
Transfer of translation adjustments related to sale of Canadian subsidiary	7,452	--	--	--	7,452
Cumulative effect of accounting change for financial derivatives	(53,573)	--	--	--	(53,573)
Change in fair value of derivative instruments	147,210	--	--	--	147,210
Reclassification of settled contracts	(48,623)	--	--	--	(48,623)
Ineffectiveness portion of derivatives qualifying for hedge accounting	(1,503)	--	--	--	(1,503)
Equity in net other comprehensive income (loss) of subsidiaries	--	--	47,412	(47,412)	--
Comprehensive income (loss)	$ 285,316	$ 2,064	$ 264,818	$(287,380)	$ 264,818

3. NOTES PAYABLE AND LONG-TERM DEBT

Notes payable and long-term debt consist of the following:

	DECEMBER 31, 2000	DECEMBER 31, 2001
	($ IN THOUSANDS)	
7.875% Senior Notes (see note 2)	$ 150,000	$ 150,000
Discount on 7.875% Senior notes	(55)	(38)
8.5% Senior Notes (see note 2)	150,000	142,665
Discount on 8.5% Senior notes	(657)	(506)
8.125% Senior Notes (see note 2)	--	800,000
Discount on 8.125% Senior notes	--	(12,353)
8.375% Senior Notes (see note 2)	--	250,000
Discount on 8.375% Senior notes	--	(315)
9.125% Senior Notes (see note 2)	120,000	--
Discount on 9.125% Senior notes	(44)	--
9.625% Senior Notes (see note 2)	500,000	--
Note payable	1,437	602
Revolving bank credit facility	25,000	--
Total notes payable and long-term debt	945,681	1,330,055
Less -- current maturities	(836)	(602)
Notes payable and long-term debt, net of current maturities	$ 944,845	$ 1,329,453

We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of December 31, 2001, we had no outstanding borrowings under this facility and had $1.1 million of the facility securing various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically. The maturity of the bank credit facility can be extended to June 2005 provided certain conditions are met.

The credit facility agreement contains various covenants and restrictive provisions including incurring additional indebtedness, selling properties, paying dividends, purchasing or redeeming our capital stock, making investments or loans, purchasing certain of our senior notes, creating liens, and making acquisitions. The credit facility agreement requires us to maintain a current ratio of at least 1 to 1 and a fixed charge coverage ratio of at least 2.5 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 or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration 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 $5.0 million.

The aggregate scheduled maturities of notes payable and long-term debt for the five fiscal years ending December 31, 2006 and thereafter were as follows as of December 31, 2001 ($ in thousands):

2002	$ 602
2003	--
2004	149,962
2005	--
2006	--
After 2006	1,179,491
	$1,330,055

4. CONTINGENCIES AND COMMITMENTS

West Panhandle Field Cessation Cases. One of our subsidiaries, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. have been defendants in 16 lawsuits filed between June 1997 and December 2001 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which we acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees. The plaintiffs in these cases have claimed the leases terminated upon the cessation of production for various periods, primarily during the 1960s. In addition, the plaintiffs have sought to recover conversion damages, exemplary damages, attorneys' fees and interest. The defendants have asserted that any cessation of production was excused and have pled affirmative defenses of

limitations, waiver, temporary estoppel, laches and title by adverse possession. Four of the 16 cases have been tried, and there have been appellate decisions in three of them.

In January 2001, we settled the claims of the principal plaintiffs in eight cases tried or pending in the District Court of Moore County, Texas, 69th Judicial District. The settlement was not material to our financial condition or results of operations. In December 2001, the Texas Supreme Court accepted for review petitions we filed with respect to the claims of plaintiffs in two of these cases who were not covered by the settlement. The Court heard oral arguments in March 2002.

There are eight other related West Panhandle cessation cases which continue to be pending, three in the District Court of Moore County, Texas, 69th Judicial District, two in the District Court of Carson County, Texas, 100th Judicial District, and three in the U.S. District Court, Northern District of Texas, Amarillo Division. In one of the Moore County cases, CP and the other defendants have appealed a January 2000 judgment notwithstanding verdict in favor of plaintiffs. In addition to quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs, the court awarded actual damages against CP in the amount of $716,400 and exemplary damages in the amount of $25,000. The court further awarded, jointly and severally from all defendants, $160,000 in attorneys' fees and interest and court costs. On March 28, 2001, the Amarillo Court of Appeals reversed and rendered judgment in favor of CP and the other defendants, finding that the subject leases had been revived as a matter of law, making all other issues moot. Plaintiffs have filed petitions requesting that the Texas Supreme Court accept the case for review. In another of the Moore County, Texas cases, in June 1999, the court granted plaintiffs' motion for summary judgment in part, finding that the lease had terminated due to the cessation of production, subject to the defendants' affirmative defenses. In February 2001, the court granted plaintiffs' motion for summary judgment on defendants' affirmative defenses but reversed its ruling that the lease had terminated as a matter of law. In one of the U.S. District Court cases, after a trial in May 1999, the jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches and revivor. Plaintiffs have moved for a new trial. There are motions pending in two other cases, and the remaining three cases are in the pleading stage.

We have previously established an accrued liability we believe will be sufficient to cover the estimated costs of litigation for each of the pending cases. Because of the inconsistent verdicts reached by the juries in the four cases tried to date and because the amount of damages sought is not specified in all of the pending cases, the outcome of any future trials and the amount of damages that might ultimately be awarded could differ from management's estimates. CP and the other defendants are vigorously defending against the plaintiffs' claims.

Chesapeake is currently involved in various other routine disputes incidental to its business operations. Management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position or results of operations of Chesapeake.

Chesapeake has employment agreements with its chief executive officer, chief operating officer and 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 agreements with the chief executive officer and chief operating officer have terms of five years commencing July 1, 2001. The term of each agreement is automatically extended for one additional year on each June 30 unless one of the parties provides 30 days notice of non-extension. The agreements with the chief financial officer and other senior managers expire on June 30, 2003. The employment agreements with the chief executive officer and chief operating officer provide that in the event of a change in control, under some circumstances, each is entitled to receive a payment in the amount of five times his base compensation and the prior year's benefits, plus a tax gross-up payment.

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 is not aware of any potential material environmental issues or claims.

Chesapeake has entered into various operating leases for office space and equipment. Future minimum lease payments required as of December 31, 2001 related to these operating leases are as follows ($ in thousands):

2002	$1,336
2003	683
2004	567
2005	244
Total	$2,830

Rent expense, including short-term rentals, for the years ended December 31, 2001, 2000, 1999 was $6.4 million, $4.4 million and $4.1 million, respectively.

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,		
	1999	2000	2001
	($ IN THOUSANDS)		
Current	$ --	$ 1,800	$ 3,565
Deferred:			
United States	--	(266,800)	167,658
Foreign	1,764	5,592	3,736
Total	$ 1,764	$(259,408)	$ 174,959

The effective income tax expense (benefit) differed from the computed "expected" federal income tax expense (benefit) on earnings before income taxes and extraordinary item for the following reasons:

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
	($ IN THOUSANDS)		
Computed "expected" federal income tax provision	$ 12,261	$ 68,657	$ 153,428
Foreign taxes in excess of U.S. statutory rates	158	302	391
Tax percentage depletion	(240)	(191)	(195)
Change in valuation allowance	(10,956)	(329,516)	2,441
State income taxes and other	541	1,340	18,894
	$ 1,764	$(259,408)	$ 174,959

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,	
	2000	2001
	($ IN THOUSANDS)	
Deferred tax liabilities:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ (11,850)	$(171,506)
Derivative assets and other	--	(58,713)
Deferred tax liabilities	$ (11,850)	$(230,219)
Deferred tax assets:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ 50,567	$ --
Net operating loss carryforwards	216,332	295,612
Percentage depletion carryforward	1,851	2,212
Alternative minimum tax credits	1,892	2,617
Deferred tax asset	$ 270,642	$ 300,441
Net deferred tax asset (liability)	$ 258,792	$ 70,222
Less: Valuation allowance	--	(2,441)
Total deferred tax asset (liability)	$ 258,792	$ 67,781
Reflected in accompanying balance sheets as:		
Current deferred income tax asset	$ 40,819	$ --
Non-current deferred income tax asset	229,823	67,781
Non-current deferred income tax liability	(11,850)	--
	$ 258,792	$ 67,781

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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. In the fourth quarter of 2000, we eliminated our existing valuation allowance which resulted in the recognition of a $265.0 million income tax benefit. This resulted in an increase to 2000 net income of $265.0 million, or $1.75 per diluted share. Based upon results of operations as of December 31, 2000 and anticipated improvement in Chesapeake's outlook for sustained profitability, we believed that it was more likely than not that we would generate sufficient future taxable income to realize the tax benefits associated with our NOL carryforwards prior to their expiration. As of December 31, 2001, we have determined that it is more likely than not that $2.4 million of the net deferred tax assets related to Louisiana net operating losses will not be realized and have recorded a valuation allowance equal to such amounts.

At December 31, 2000, we classified $40.8 million of our deferred tax assets as current to recognize the portion of the NOL carryover that was expected to be utilized to reduce taxable income in 2001. As of December 31, 2001, we classified $48.9 million of deferred tax assets related to NOLs as current to offset the current deferred tax liability attributable to the current portion of derivative assets.

At December 31, 2001, Chesapeake had federal and state income tax net operating loss (NOL) carryforwards of approximately $757.7 million. Additionally, we had approximately $419.8 million of alternative minimum tax (AMT) NOL carryforwards available as a deduction against future AMT income and approximately $5.7 million of percentage depletion carryforwards. The NOL carryforwards expire from 2010 through 2021. 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, 2010	$ 5,724	$ --
December 31, 2011	26,080	--
December 31, 2012	250,657	18,237
December 31, 2018	238,552	177,824
December 31, 2019	223,952	212,168
December 31, 2020	3,976	3,998
December 31, 2021	8,766	7,550
Total	$757,707	$419,777

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 or 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. Chesapeake had ownership changes in January 1995 and March 1998 which triggered limitations. Certain NOLs acquired through various acquisitions are also subject to limitations. Of the $757.7 million NOLs and $419.8 million AMT NOLs, $339.5 million and $84.1 million, respectively, are limited under Section 382. Therefore, $418.2 million of the NOLs and $335.7 million of the AMT NOLs are not subject to the limitation. The utilization of $339.5 million of the NOLs and the utilization of $84.1 million of the AMT NOLs subject to the Section 382 limitation are limited to approximately $37.9 million and $12.3 million, respectively, each taxable year. Although no assurances can be made, we do not believe that an additional ownership change has occurred as of December 31, 2001. Equity transactions after the date hereof by Chesapeake or by 5% stockholders (including relatively small transactions and transactions beyond our control) could cause an ownership change and therefore a limitation on the annual utilization of NOLs.

6. RELATED PARTY TRANSACTIONS

Since Chesapeake was founded in 1989, our chief executive officer and chief operating officer have acquired small working interests in certain of our oil and gas properties by participating in our drilling activities. As of December 31, 2001, we had accounts receivable from our CEO and COO of $5.0 million and $4.9 million, respectively, representing joint interest billings payable within 90 days. Under their employment agreements, the CEO and COO are permitted to participate in all, or none, of the wells spudded by or on behalf of Chesapeake during each calendar quarter, but they are not allowed to only participate in select 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 a quarter. Their participation is permitted only under the terms outlined in their employment agreements, which, among other things, limit their 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.

As of December 31, 1998, our CEO and COO had notes payable to Chesapeake Energy Marketing, Inc..in the principal amount of $9.9 million. In November 1999, our CEO and COO tendered 2,320,107 shares of Chesapeake common stock in full satisfaction of the notes, which had a combined outstanding balance of $7.6 million. The common stock was valued at $3.29 per share, which was the market value of the stock at the time of the transaction.

In October 2001, we sold Chesapeake Canada Corporation, a wholly-owned subsidiary, for net proceeds of approximately $143.0 million. Our CEO and COO each received $2.0 million related to their fractional ownership interest in these Canadian assets, which they acquired and paid for pursuant to the terms of their employment agreements. The portion of the proceeds allocated to our CEO and COO was based upon the estimated fair values of the assets sold as determined by management and the independent members of our board of directors using a methodology similar to that used by Chesapeake for acquisitions of assets from disinterested third parties.

During 2001, 2000, and 1999, we paid legal fees of $391,000, $439,000 and $398,000, respectively, for legal services provided by a law firm of which a director is a member.

7. EMPLOYEE BENEFIT PLANS

We maintain the Chesapeake Energy Corporation Savings and Incentive Stock Bonus Plan, a 401(k) profit sharing plan. Eligible employees may make voluntary contributions to the plan which Chesapeake matches up to 10% of the employee's annual salary with Chesapeake's common stock purchased in the open-market. The amount of employee contribution is limited as specified in the plan. We may, at our discretion, make additional contributions to the plan. We contributed $2.0 million, $1.5 million and $1.2 million to the plan during 2001, 2000 and 1999, respectively.

8. MAJOR CUSTOMERS AND SEGMENT INFORMATION

Sales to individual customers constituting 10% or more of total oil and gas sales were as follows:

YEAR ENDED DECEMBER 31,	CUSTOMER	AMOUNT	PERCENT OF OIL AND GAS SALES
		($ IN THOUSANDS)	
1999............	Aquila Southwest Pipeline Corporation	$ 31,505	11%
2000............	Aquila Southwest Pipeline Corporation	$ 54,931	12%
2001............	Continental Natural Gas	$102,286	14%
2001............	Reliant Energy Field Services	$ 87,628	12%
2001............	Aquila Southwest Pipeline Corporation	$ 71,868	10%

Management believes that the loss of any of the above customers would not have a material impact on our results of operations or our financial position.

Chesapeake has two reportable segments under SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, consisting of exploration and production, and marketing. The reportable segment information can be derived from note 2 as Chesapeake Energy Marketing, Inc., which is our marketing segment, is the only non-guarantor subsidiary for all periods presented. The geographic distribution of our revenue, operating income and long-lived assets is summarized below:

	UNITED STATES	CANADA	COMBINED
		($ IN THOUSANDS)	
1999:			
Revenue	$ 340,969	$ 13,977	$ 354,946
Operating income (loss)	103,188	4,332	107,520
Long-lived assets	648,841	104,146	752,987
2000:			
Revenue	$ 594,126	$ 33,826	$ 627,952
Operating income (loss)	259,828	18,941	278,769
Long-lived assets	1,163,952	109,548	1,273,500
2001:			
Revenue	$ 937,123	$ 31,928	$ 969,051
Operating income (loss)	500,231	20,049	520,280
Long-lived assets	1,925,385	--	1,925,385

9. STOCKHOLDERS' EQUITY AND STOCK-BASED COMPENSATION

In January 2001, we issued 4.0 million common shares to the Gothic shareholders. They received 0.1908 of a share of Chesapeake common stock for each share of the Gothic common stock. In addition, outstanding warrants and options to purchase Gothic common stock were converted to the right to purchase Chesapeake common stock based on the merger exchange ratio. As of December 31, 2001, 1.1 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $12.48 per share.

In 2001, holders of our 7% cumulative convertible preferred stock converted 622,768 shares into 4,480,171 shares of common stock (at a conversion price of $6.95 per share), and we redeemed the remaining 1,269 shares of preferred stock for 7,239 shares of common stock and $3,000 of cash (at a redemption price of $52.45 per share, paid in 5.7 shares of common stock and cash of $2.45).

On March 30, 2001, we issued 1.1 million shares of Chesapeake common stock in exchange for 49.5% of RAM Energy, Inc.'s, outstanding common stock. Our shares were valued at $8.854 each, or $9.9 million in total. We agreed to adjust the consideration for our acquisition of RAM shares by making a cash payment to the selling RAM shareholders equal to the shortfall if they sold the Chesapeake shares they received at a price less than $8.854 per share. In the third quarter of 2001, the RAM shareholders sold all their shares of Chesapeake common stock at prices below this level and we made make-whole cash payments of $3.3 million to them to cover the shortfall. In December 2001, we sold all the RAM shares we owned for minimal consideration.

On September 21, 2001, our board of directors authorized the repurchase of up to $50 million of our common stock, either through direct purchases or put options. We have not made any repurchases or written any put options to date under this program. The consent to the stock repurchase program we obtained under our bank credit facility expires June 30, 2002.

On November 13, 2001, we issued 3.0 million shares of 6.75% cumulative convertible preferred stock, par value $.01 per share and liquidation preference $50 per share, in a private offering. The net proceeds from the offering were $145.1 million. Each preferred share is convertible at any time at the option of the holder into 6.4935 shares of our common stock, subject to adjustment. At December 31, 2001, 19,480,500 shares of our common stock were reserved for issuance upon conversion. The conversion rate is based on an initial conversion price of $7.70 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 20, 2004 at the same rate if the market price of the common stock equals or exceeds 130% of the conversion price at the time and (2) on or after November 20, 2006 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. Annual cumulative cash dividends of $3.375 per share are payable quarterly on the fifteenth day of each February, May, August and November.

During 2000, we entered into a number of unsolicited transactions whereby we issued 43.4 million shares of our common stock, plus a cash payment of $8.3 million, in exchange for 3,972,363 shares of our preferred stock. This reduced the liquidation amount of preferred stock outstanding by $198.6 million to $31.2 million and reduced the amount of preferred dividends in arrears by $22.9 million.

During 2000, Chesapeake Energy Marketing, Inc. purchased 99.8% of Gothic Energy Corporation's $104 million 14.125% Series B senior secured discount notes for total consideration of $80.8 million, comprised of $17.2 million in cash and $63.6 million of our common stock (8,875,775 shares valued at $7.16 per share), as adjusted for make-whole provisions. Chesapeake Energy Marketing, Inc. received $6.1 million in cash and $7.2 million of our common stock (982,562 shares) from the sellers of Gothic notes pursuant to make-whole provisions included in the purchase agreements. These provisions required payments to be made by the sellers to us or additional payments to be made by us to the sellers, depending upon changes in market value of our common stock during a specified period pending registration of our common stock issued to the sellers of Gothic notes.

In 2000, we purchased $31.6 million of the $235 million of 11.125% senior secured notes issued by Gothic Production Corporation for total consideration of $34.8 million consisting of $11.5 million in cash and $23.3 million of our common stock (3,694,939 shares valued at $6.30 per share), as adjusted for make-whole provisions similar to those described above. Through the make-whole provisions, we received cash of $1.0 million.

In November 1999, the chief executive officer and the chief operating officer of Chesapeake tendered to Chesapeake Energy Marketing, Inc. 2,320,107 shares of Chesapeake common stock in full satisfaction of two notes payable to CEMI with a combined outstanding balance of $7.6 million. At the time, Chesapeake's stock price was $3.29 per share. See note 6.

Stock Option Plans

Under Chesapeake's 2001 Stock Option Plan, incentive and nonqualified stock options to purchase our common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 3,200,000 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 options on the date of grant; provided, however, nonqualified stock options not exceeding 10% of the options issuable under this plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the Stock Option Committee of the board of directors. No options can be granted under this plan after February 28, 2011.

Under Chesapeake's 2000 and 2001 Executive Officer Stock Option Plans, nonqualified stock options to purchase our common stock may be granted to executive officers of Chesapeake. Subject to any adjustment as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 2,500,000 shares under the 2000 Plan and 4,000,000 shares under the 2001 Plan and must represent issued shares which have been reacquired by Chesapeake. 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 this plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the Stock Option Committee of the board of directors. No options can be granted under the 2000 plan after April 25, 2010 or after April 14, 2011 under the 2001 Plan.

Under Chesapeake's 1999 Stock Option Plan, 2000 Employee Stock Option Plan and our 2001 Nonqualified Stock Option Plan, nonqualified stock options to purchase our common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by the respective plans, the aggregate number of shares which may be issued and sold may not exceed 3,000,000 shares from each plan. 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 this plan may be granted at an exercise price which is not less than 85% of the grant date fair market value. Options granted become exercisable at dates determined by the Stock Option Committee of the board of directors. No options can be granted after March 4, 2009 under the 1999 Plan, after April 25, 2010 under the 2000 Employee Plan and after April 14, 2011 under the 2001 Nonqualified Plan.

Under Chesapeake's 1994 Stock Option Plan, and our 1996 Stock Option Plan, incentive and nonqualified stock options to purchase our common stock may be granted to employees and consultants of Chesapeake. Subject to any adjustment as provided by the respective plans, the aggregate number of shares which may be issued and sold may not exceed 4,886,910 shares under the 1994 Plan and 6,000,000 shares under the 1996 Plan. The maximum period for exercise of an option may not be more than ten years from the date of grant and the exercise price of nonqualified stock options may not be less than par value and, under the 1996 Plan, 85% of the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the Stock Option Committee of the board of directors. No options can be granted under the 1994 Plan after October 17, 2004 or under the 1996 Plan after October 14, 2006.

Under our 1992 Nonstatutory Stock Option Plan, non-qualified options to purchase our common stock may be granted only to directors and consultants of Chesapeake. Subject to any adjustment as provided by this plan, the aggregate number of shares which may be issued and sold may not exceed 3,132,000 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 options on the date of grant. Options granted become exercisable at dates determined by the Stock Option Committee of the board of directors. This plan also contains a formula award provision pursuant to which each director who is not an executive officer receives every quarter a ten-year immediately exercisable option to purchase 8,750 shares of common stock at an option price equal to the fair market value of the shares on the date of grant. The amount of the award was changed from 20,000 shares to 15,000 shares per year in 1998, to 25,000 shares per year in 1999, to 30,000 shares per year in 2000 and to 35,000 shares per year in 2001. No options can be granted under this plan after December 10, 2002.

Chesapeake's 1992 Incentive Stock Option Plan terminated on December 16, 1994. Until then, we granted incentive stock options to purchase our common stock under the ISO Plan to employees. Subject to any adjustment as provided by the ISO Plan, the aggregate number of shares which may be issued and sold may not exceed 3,762,000 shares. The maximum period for exercise of an option may not be more than ten years (or five years for an optionee who owns more than 10% of the common stock) 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 (or 110% of such value for an optionee who owns more than 10% of the common stock). Options granted become exercisable at dates determined by the Stock Option Committee of the board of directors.

Chesapeake has elected to follow APB No. 25, Accounting for Stock Issued to Employees and related interpretations in accounting for its employee stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. In March 2000, the Financial Accounting Standards Board issued FASB Interpretation No. 44 which provided clarification regarding the application of APB No. 25. FIN 44 specifically addressed the accounting consequence of various modifications to the terms of a previously granted fixed stock option. Compensation expense of $0.8 million was recognized in 2001 as a result of modifications that were made during the years ended December 31, 2001 and 2000. No compensation expense has been recognized for newly issued stock options in 2001, 2000 or 1999 because the exercise price of the stock options granted under the plans equaled the market price of the underlying stock on the date of grant.

Pro forma information regarding net income and earnings per share is required by SFAS No. 123 and has been determined as if we had accounted for our employee 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 2001, 2000 and 1999, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) of 4.67%, 6.32% and 5.88%, dividend yields of 0.0%, 0.0% and 0.0%, volatility factors of the expected market price of our common stock of 0.58, 0.73, and 0.82, and weighted-average expected life of the options of five years.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options which have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. Because our employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion the existing models do not necessarily provide a reliable single measure of the fair value of its employee stock options.

Pro forma information applying the fair value method follows:

	YEARS ENDED DECEMBER 31,		
	1999	2000	2001
	($ IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)		
Net Income			
As reported	$ 33,266	$455,570	$217,406
Pro forma	24,802	444,865	202,301
Basic Earnings per Common Share			
As reported	$ 0.17	$ 3.52	$ 1.33
Pro forma	0.08	3.43	1.23
Diluted Earnings per Common Share			
As reported	$ 0.16	$ 3.01	$ 1.25
Pro forma	0.08	2.94	1.16

For purposes of the pro forma disclosures, the estimated fair value of the options is amortized to expense over the options' vesting period, which is four years. Because our stock options vest over four years and additional awards are typically made each year, the above pro forma disclosures are not likely to be representative of the effects on pro forma net income for future years. A summary of our stock option activity and related information follows:

	YEARS ENDED DECEMBER 31,					
	1999		2000		2001	
	OPTIONS	WEIGHTED-AVG EXERCISE PRICE	OPTIONS	WEIGHTED-AVG EXERCISE PRICE	OPTIONS	WEIGHTED-AVG EXERCISE PRICE
Outstanding Beginning of Period	11,260,375	$1.86	12,858,429	$1.76	18,399,162	$2.83
Granted	3,210,493	1.11	8,143,280	4.08	7,422,300	6.18
Exercised	(622,120)	0.99	(2,177,644)	1.21	(2,264,374)	1.83
Canceled/Forfeited	(990,319)	1.87	(424,903)	2.47	(324,433)	5.68
Outstanding End of Period	12,858,429	$1.76	18,399,162	$2.83	23,232,655	$3.96
Exercisable End of Period	5,040,302	$2.66	5,422,884	$2.61	7,495,255	$2.88
Shares Authorized for Future Grants	2,560,687		588,435		3,836,856	
Fair Value of Options Granted During the Period	$ 0.77		$ 2.63		$ 3.34	

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65

The following table summarizes information about stock options outstanding at December 31, 2001:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING	WEIGHTED-AVG. REMAINING CONTRACTUAL LIFE	WEIGHTED-AVG. EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED-AVG. EXERCISE PRICE
$0.08-$0.94	2,206,511	5.84	$ 0.87	1,040,054	$ 0.78
1.00-1.13	4,424,701	6.77	1.13	2,827,632	1.13
1.33-2.25	2,919,793	6.26	2.18	1,225,388	2.07
2.43-3.81	370,622	4.10	2.99	353,062	2.99
4.00	2,496,612	8.31	4.00	584,713	4.00
4.06-5.50	65,232	5.22	4.61	40,909	4.68
5.56	2,893,286	8.84	5.56	722,796	5.56
5.60-6.10	144,563	5.57	5.76	121,563	5.75
6.11	7,030,550	9.74	6.11	--	--
6.13-30.63	680,785	5.89	10.90	579,138	11.65
$0.08-$30.63	23,232,655	7.86	$ 3.96	7,495,255	$ 2.88

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 2001 and 2000, we recognized a tax benefit of $5.4 million and $3.8 million, which was recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits. There was no similar tax benefit in 1999.

Shareholder Rights Plan

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

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

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

10. FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of this exposure to adverse market changes, we have entered into derivative instruments. All of our derivative instruments have been entered into as hedges of oil and gas price risk and not for speculative purposes.

We utilize derivative instruments to reduce exposure to unfavorable changes in oil and gas prices which are subject to significant and often volatile fluctuations. As of December 31, 2001, our derivative instruments were comprised of swaps, collars, cap-swaps, and locked swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, 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.

- 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, then we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, then no payments are due from either party.

- For cap-swaps, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" on the floating market price, which limits the counterparty's exposure.

- Locked swaps consist of swap positions which have been effectively closed by entering into a counter-swap instrument where we receive the floating price for the hedged commodity and pay a fixed price to the counterparty. At the time we enter into the counter-swap, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133. The net values of both the swap and counter-swap are frozen and shown as derivatives receivable or payable in the consolidated balance sheet.

Pursuant to SFAS 133, our cap-swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity are reported in the statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and recorded in oil and gas sales over the respective contract terms.

The estimated fair values of our derivative instruments as of December 31, 2001 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	DECEMBER 31, 2001 ($ IN THOUSANDS)
Derivative assets:	
Fixed-price gas cap-swaps	$ 77,208
Fixed-price gas locked swaps	50,549
Fixed-price gas collars	15,360
Fixed-price gas swaps	6,268
Fixed-price crude oil cap-swaps	5,078
Fixed-price crude oil locked swaps	2,846
Total	$157,309

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties. 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 fair value estimates used at December 31, 2001.

Risk management income in the consolidated statement of operations for 2001 is comprised of the following:

	2001 ($ IN THOUSANDS)
Risk Management Income:	
Change in fair value of derivatives not qualifying for hedge accounting	$ 106,825
Reclassification of settled contracts	(24,540)
Ineffective portion of derivatives qualifying for hedge accounting	2,504
Total	$ 84,789

Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

We expect to transfer approximately $33.7 million of the balance in accumulated other comprehensive income, based upon the market prices at December 31, 2001, to earnings during the next 12 months when the forecasted transactions actually occur. All forecasted transactions hedged as of December 31, 2001 are expected to occur by December 2003.

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 value amounts 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 (including current maturities), fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt at December 31, 2001 and 2000 was $1,330.1 million and $920.7 million, respectively, compared to approximate fair values of $1,343.0 million and $894.7 million, respectively. The carrying value of other long-term debt approximates its fair value as interest rates are primarily variable, based on prevailing market rates. The carrying amount for our 6.75% convertible preferred stock at December 31, 2001 was $150.0 million, which approximated its fair value as of that date.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and cash equivalents, including restricted cash, and 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. Our mark-to-market position and closed but uncollected receivable with our largest counterparty, Morgan Stanley Capital Group Inc., totaled $137.8 million at December 31, 2001. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. 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. The 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. Cash and cash equivalents are deposited with major banks or institutions.

11. 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, 2000	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas properties:			
Proved	$ 2,453,316	$ 137,196	$ 2,590,512
Unproved	23,673	2,012	25,685
Total	2,476,989	139,208	2,616,197
Less accumulated depreciation, depletion and amortization	(1,737,892)	(32,935)	(1,770,827)
Net capitalized costs	$ 739,097	$ 106,273	$ 845,370

DECEMBER 31, 2001	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas properties:			
Proved	$ 3,546,163	$ --	$ 3,546,163
Unproved	66,205	--	66,205
Total	3,612,368	--	3,612,368
Less accumulated depreciation, depletion and amortization	(1,902,587)	--	(1,902,587)
Net capitalized costs	$ 1,709,781	$ --	$ 1,709,781

Unproved properties not subject to amortization at December 31, 2001 and 2000 consisted mainly of lease acquisition costs. We capitalized approximately $4.7 million, $2.4 million and $3.5 million of interest during 2001, 2000 and 1999, 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.

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:

YEAR ENDED DECEMBER 31, 1999	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Development and leasehold costs	$ 92,582	$ 31,536	$ 124,118
Exploration costs	23,651	42	23,693
Acquisition costs:			
Proved	47,993	4,100	52,093
Unproved	2,747	--	2,747
Sales of oil and gas properties	(44,822)	(813)	(45,635)
Capitalized internal costs	2,710	--	2,710
Total	$ 124,861	$ 34,865	$ 159,726

YEAR ENDED DECEMBER 31, 2000	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Development and leasehold costs	$ 138,285	$ 13,559	$ 151,844
Exploration costs	24,648	10	24,658
Acquisition costs:			
Proved	75,285	--	75,285
Unproved	3,625	--	3,625
Sales of oil and gas properties	(1,529)	--	(1,529)
Capitalized internal costs	6,958	--	6,958
Total	$ 247,272	$ 13,569	$ 260,841

YEAR ENDED DECEMBER 31, 2001	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Development and leasehold costs	$ 339,683	$ 11,090	$ 350,773
Exploration costs	47,937	8	47,945
Acquisition costs:			
Proved	705,510	--	705,510
Unproved	35,132	--	35,132
Sales of oil and gas properties	(1,138)	(150,306)	(151,444)
Capitalized internal costs	8,255	--	8,255
Total	$1,135,379	$(139,208)	$ 996,171

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 1999, 2000 and 2001. The following table includes revenues and expenses associated directly with our oil and gas producing activities. It does not include any interest costs and general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil and gas operations.

YEAR ENDED DECEMBER 31, 1999	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Oil and gas sales	$ 266,468	$ 13,977	$ 280,445
Production expenses	(44,165)	(2,133)	(46,298)
Production taxes	(13,264)	--	(13,264)
Depletion and depreciation	(88,901)	(6,143)	(95,044)
Imputed income tax provision (a)	(45,052)	(2,565)	(47,617)
Results of operations from oil and gas producing activities	$ 75,086	$ 3,136	$ 78,222

YEAR ENDED DECEMBER 31, 2000	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Oil and gas sales	$ 436,344	$ 33,826	$ 470,170
Production expenses	(46,280)	(3,805)	(50,085)
Production taxes	(24,840)	--	(24,840)
Depletion and depreciation	(92,708)	(8,583)	(101,291)
Imputed income tax provision (a)	(103,556)	(9,647)	(113,203)

	U.S.	CANADA	COMBINED
Results of operations from oil and gas producing activities	$ 168,960	$ 11,791	$ 180,751

YEAR ENDED DECEMBER 31, 2001	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas sales	$ 703,601	$ 31,928	$ 735,529
Production expenses	(73,016)	(2,358)	(75,374)
Production taxes	(33,010)	--	(33,010)
Depletion and depreciation	(164,693)	(8,209)	(172,902)
Imputed income tax provision (a)	(173,153)	(9,612)	(182,765)
Results of operations from oil and gas producing activities	$ 259,729	$ 11,749	$ 271,478

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

Oil and Gas Reserve Quantities (unaudited)

The reserve information presented below is based upon reports prepared by independent petroleum engineers and Chesapeake's petroleum engineers.

- As of December 31, 2001, Ryder Scott Company L.P., Lee Keeling and Associates, Williamson Petroleum Consultants, Inc. and our internal reservoir engineers evaluated 26%, 24%, 22% and 28%, respectively, of the combined discounted future net revenues from our estimated proved reserves.

- As of December 31, 2000, Williamson, Ryder Scott, Lee Keeling and Associates and our internal reservoir engineers evaluated 31%, 25%, 16% and 28%, respectively, of the combined discounted future net revenues from our estimated proved reserves.

- As of December 31, 1999, Williamson, Ryder Scott, and our internal reservoir engineers evaluated 50%, 16%, and 34%, respectively, of the combined discounted future net revenues from our estimated proved reserves.

The information 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. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of changes in estimated reserves of Chesapeake for 1999, 2000 and 2001:

DECEMBER 31, 1999

	U.S.			CANADA			COMBINED		
	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)
Proved reserves, beginning of period	22,560	724,018	859,377	33	231,773	231,971	22,593	955,791	1,091,348
Extensions, discoveries and other additions	4,593	158,801	186,359	--	37,835	37,835	4,593	196,636	224,194
Revisions of previous estimates	3,404	59,904	80,328	--	(98,571)	(98,571)	3,404	(38,667)	(18,243)
Production	(4,147)	(96,873)	(121,755)	--	(11,737)	(11,737)	(4,147)	(108,610)	(133,492)
Sale of reserves-in-place	(4,371)	(31,616)	(57,842)	(33)	(796)	(994)	(4,404)	(32,412)	(58,836)
Purchase of reserves-in-place	2,756	64,350	80,886	--	19,738	19,738	2,756	84,088	100,624
Proved reserves, end of period	24,795	878,584	1,027,353	--	178,242	178,242	24,795	1,056,826	1,205,595
Proved developed reserves:									
Beginning of period	18,003	552,953	660,971	33	105,990	106,188	18,036	658,943	767,159
End of period	17,750	627,120	733,620	--	136,203	136,203	17,750	763,323	869,823

DECEMBER 31, 2000

	U.S.			CANADA			COMBINED		
	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)
Proved reserves, beginning of period	24,795	878,584	1,027,353	--	178,242	178,242	24,795	1,056,826	1,205,595
Extensions, discoveries and other additions	3,599	157,719	179,313	--	20,772	20,772	3,599	178,491	200,085
Revisions of previous estimates	(3,210)	25,652	6,392	--	(27,973)	(27,973)	(3,210)	(2,321)	(21,581)
Production	(3,068)	(103,694)	(122,102)	--	(12,077)	(12,077)	(3,068)	(115,771)	(134,179)
Sale of reserves-in-place	(136)	(2,155)	(2,971)	--	--	--	(136)	(2,155)	(2,971)
Purchase of reserves-in-place	1,817	96,963	107,864	--	--	--	1,817	96,963	107,864
Proved reserves, end of period	23,797	1,053,069	1,195,849	--	158,964	158,964	23,797	1,212,033	1,354,813
Proved developed reserves:									
Beginning of period	17,750	627,120	733,620	--	136,203	136,203	17,750	763,323	869,823
End of period	15,445	739,775	832,445	--	118,688	118,688	15,445	858,463	951,133

DECEMBER 31, 2001

	U.S.			CANADA			COMBINED		
	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)	OIL (mbbl)	GAS (mmcf)	TOTAL (mmcfe)
Proved reserves, beginning of period	23,797	1,053,069	1,195,849	--	158,964	158,964	23,797	1,212,033	1,354,813
Extensions, discoveries and									

other additions	2,425	256,616	271,167	--	--	--	2,425	256,616	271,167
Revisions of previous estimates	(2,750)	(166,146)	(182,644)	--	--	--	(2,750)	(166,146)	(182,644)
Production	(2,880)	(135,096)	(152,376)	--	(9,075)	(9,075)	(2,880)	(144,171)	(161,451)
Sale of reserves-in-place	--	--	--	--	(149,889)	(149,889)	--	(149,889)	(149,889)
Purchase of reserves-in-place	9,501	590,943	647,950	--	--	--	9,501	590,943	647,950
Proved reserves, end of period	30,093	1,599,386	1,779,946	--	--	--	30,093	1,599,386	1,779,946
Proved developed reserves:									
Beginning of period	15,445	739,775	832,445	--	118,688	118,688	15,445	858,463	951,113
End of period	22,496	1,134,381	1,269,359	--	--	--	22,496	1,134,381	1,269,359

During 2001, Chesapeake acquired 648 bcfe of proved reserves for consideration of $706 million in approximately 160 separate transactions. In October 2001, we sold our Canadian subsidiary, which had oil and gas operations primarily in northeast British Columbia, for approximately $143.0 million. Also during 2001, we recorded downward revisions to our U.S. oil and gas reserves of 183 bcfe. Approximately 156 bcfe of the downward revisions to our reserves were related to significantly lower gas and oil prices at December 31, 2001, which had the effect of reducing the economic life of our properties. The weighted average oil and gas wellhead prices used in computing our reserves were $18.82 per bbl and $2.51 per mcf at December 31, 2001, compared to $26.41 per bbl and $10.12 per mcf at December 31, 2000.

During 2000, Chesapeake acquired 108 bcfe of proved reserves for consideration of $75 million. Also during 2000, we recorded downward revisions to our U.S. oil reserves of 3.2 million barrels and upward revisions to our U.S. natural gas reserves of 25.7 bcf. The downward revisions to our U.S. oil reserves were related to lower estimates primarily in the Knox, Permian and Williston areas. The upward revisions to our U.S. gas reserves were due primarily to additional reserves added as a result of the significant increase in natural gas prices as of December 31, 2000, which had the effect of extending the economic life of our properties. These upward revisions were partially offset by the elimination of proved undeveloped locations primarily in the Knox, Independence and Sahara fields, as well as lower estimates in various areas located primarily in the Mid-Continent area. During 2000, we also had negative revisions to our Canadian gas reserves of 28 bcf. This decrease was primarily due to the increase in crown royalties resulting from higher natural gas prices at December 31, 2000, as well as lower estimates on various properties in the Helmet field.

During 1999, Chesapeake acquired approximately 101 bcfe of proved reserves through purchases of oil and gas properties for consideration of $52 million. We also sold 59 bcfe of proved reserves for consideration of approximately $46 million. During 1999, we recorded upward revisions of 80 bcfe to the December 31, 1998 estimates of our U.S. reserves, and downward revisions of 99 bcfe to the December 31, 1998 estimates of our Canadian reserves, for a total revision of 19 bcfe, or approximately 1.7%. The upward revisions to our U.S. reserves were caused by higher oil and gas prices at December 31, 1999, and actual performance in excess of predicted performance. Higher prices extend the economic lives of the underlying oil and gas properties and thereby increase the estimated future reserves. The downward revisions of our Canadian reserves were caused by a reduction of our proved undeveloped locations and an increase in projected transportation and operating costs in Canada, which decreased the economic lives of the underlying properties.

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. 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 are the basis for the valuation process.

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:

DECEMBER 31, 1999

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Future cash inflows(a)	$ 2,555,241	$ 437,928	$ 2,993,169
Future production costs	(671,431)	(195,464)	(866,895)
Future development costs	(209,921)	(20,950)	(230,871)
Future income tax provision	(219,866)	(29,410)	(249,276)
Net future cash flows	1,454,023	192,104	1,646,127
Less effect of a 10% discount factor	(545,125)	(94,390)	(639,515)
Standardized measure of discounted future net cash flows	$ 908,898	$ 97,714	$ 1,006,612
Discounted (at 10%) future net cash flows before income taxes	$ 991,748	$ 97,748	$ 1,089,496

DECEMBER 31, 2000

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Future cash inflows(b)	$ 11,336,112	$ 1,540,158	$ 12,876,270
Future production costs	(1,778,325)	(79,427)	(1,857,752)
Future development costs	(294,359)	(21,185)	(315,544)
Future income tax provision	(3,247,701)	(447,887)	(3,695,588)
Net future cash flows	6,015,727	991,659	7,007,386
Less effect of a 10% discount factor	(2,440,407)	(503,718)	(2,944,125)
Standardized measure of discounted future net cash flows	$ 3,575,320	$ 487,941	$ 4,063,261
Discounted (at 10%) future net cash flows before income taxes	$ 5,365,228	$ 680,800	$ 6,046,028

DECEMBER 31, 2001

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Future cash inflows(c)	$ 4,586,743	$ --	$ 4,586,743
Future production costs	(1,169,199)	--	(1,169,199)
Future development costs	(450,181)	--	(450,181)
Future income tax provision	(484,474)	--	(484,474)
Net future cash flows	2,482,889	--	2,482,889
Less effect of a 10% discount factor	(1,021,916)	--	(1,021,916)
Standardized measure of discounted future net cash flows	$ 1,460,973	$ --	$ 1,460,973
Discounted (at 10%) future net cash flows before income taxes	$ 1,646,667	$ --	$ 1,646,667

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(a) Calculated using weighted average prices of $24.72 per barrel of oil and $2.25 per mcf of gas.

(b) Calculated using weighted average prices of $26.41 per barrel of oil and $10.12 per mcf of gas.

(c) Calculated using weighted average prices of $18.82 per barrel of oil and $2.51 per mcf of gas.

In October 2001, we sold our Canadian subsidiary, which had oil and gas operations primarily in northeast British Columbia, for net proceeds of approximately $143.0 million.

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

DECEMBER 31, 1999

	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Standardized measure, beginning of period	$ 507,127	$ 115,988	$ 623,115
Sales of oil and gas produced, net of production costs	(209,039)	(11,844)	(220,883)
Net changes in prices and production costs	320,123	(55,156)	264,967
Extensions and discoveries, net of production and development costs	200,787	14,333	215,120
Changes in future development costs	(15,011)	20,679	5,668
Development costs incurred during the period that reduced future development costs	14,114	1,985	16,099
Revisions of previous quantity estimates	88,250	(49,034)	39,216
Purchase of reserves-in-place	66,895	18,476	85,371
Sales of reserves-in-place	(25,838)	(920)	(26,758)
Accretion of discount	50,415	15,684	66,099
Net change in income taxes	(85,828)	40,821	(45,007)
Changes in production rates and other	(3,097)	(13,298)	(16,395)
Standardized measure, end of period	$ 908,898	$ 97,714	$ 1,006,612

DECEMBER 31, 2000

	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Standardized measure, beginning of period	$ 908,898	$ 97,714	$ 1,006,612
Sales of oil and gas produced, net of production costs	(365,224)	(30,021)	(395,245)
Net changes in prices and production costs	2,750,651	573,654	3,324,305
Extensions and discoveries, net of production and development costs	878,128	87,647	965,775
Changes in future development costs	2,167	3,233	5,400
Development costs incurred during the period that reduced future development costs	38,112	6,415	44,527
Revisions of previous quantity estimates	25,818	(113,473)	(87,655)
Purchase of reserves-in-place	494,483	--	494,483
Sales of reserves-in-place	(3,113)	--	(3,113)
Accretion of discount	99,175	9,775	108,950
Net change in income taxes	(1,707,060)	(192,825)	(1,899,885)
Changes in production rates and other	453,285	45,822	499,107
Standardized measure, end of period	$ 3,575,320	$ 487,941	$ 4,063,261

DECEMBER 31, 2001

	U.S.	CANADA	COMBINED
	($ IN THOUSANDS)		
Standardized measure, beginning of period	$ 3,575,320	$ 487,941	$ 4,063,261
Sales of oil and gas produced, net of production costs	(597,575)	(29,570)	(627,145)
Net changes in prices and production costs	(4,284,926)	--	(4,284,926)
Extensions and discoveries, net of production and development costs	292,051	--	292,051
Changes in future development costs	75,694	--	75,694
Development costs incurred during the period that reduced future development costs	32,955	--	32,955
Revisions of previous quantity estimates	(151,455)	--	(151,455)
Purchase of reserves-in-place	816,865	--	816,865
Sales of reserves-in-place	(157)	(458,371)	(458,528)
Accretion of discount	536,523	--	536,523
Net change in income taxes	1,604,216	--	1,604,216
Changes in production rates and other	(438,538)	--	(438,538)
Standardized measure, end of period	$ 1,460,973	$ --	$ 1,460,973

12. ACQUISITIONS, INVESTMENTS AND DIVESTITURES

We completed the acquisition of Gothic Energy Corporation on January 16, 2001 by merging a wholly-owned subsidiary into Gothic. We issued a total of 4.0 million common shares in the merger. Gothic shareholders (other than Chesapeake) received 0.1908 of a share of Chesapeake common stock for each share of Gothic common stock. In addition, outstanding warrants and options to purchase Gothic common stock were converted to the right to purchase Chesapeake common stock based on the merger exchange ratio. As of December 31, 2001, 1.1 million shares of Chesapeake common stock may be purchased upon the exercise of such warrants and options at an average price of $12.48 per share. In 2000, Chesapeake purchased substantially all of Gothic's 14.125% senior secured discount notes for total consideration of $80.8 million in cash and Chesapeake common stock. We also purchased $31.6 million principal amount of 11.125% senior secured notes due 2005 issued by Gothic's operating subsidiary for total consideration of $34.8 million in cash and Chesapeake common stock. Subsequent to the acquisition, we redeemed all remaining Gothic 14.125% discount notes for total consideration of $243,000. In February 2001, we purchased $1.0 million principal amount of Gothic senior secured notes tendered pursuant to a change-of-control offer at a purchase price of 101%. During April and May 2001, we purchased or redeemed the remaining $202.3 million of Gothic 11.125% senior secured notes for total consideration of $225.9 million. On May 14, 2001, Gothic Energy Corporation and Gothic Production Corporation became guarantor subsidiaries of Chesapeake's senior notes.

During 2000, we obtained a standby commitment for a $275 million credit facility, consisting of a $175 million term loan and a $100 million revolving credit facility which, if needed, would have replaced our then existing revolving credit facility. The term loan was available to provide funds to repurchase any of Gothic Production Corporation's 11.125% senior secured notes tendered following the closing of the Gothic acquisition in January 2001 pursuant to a change-of-control offer to purchase. In February 2001, we purchased $1.0 million of notes tendered for 101% of such amount. We did not use the standby credit facility and the commitment terminated on February 23, 2001. Chesapeake incurred $3.4 million of costs for the standby facility, which were recognized in the first quarter of 2001.

The acquisition of Gothic was accounted for using the purchase method as of January 1, 2001 because we had effective control as of that date, and the results of operations of Gothic have been included since that date.

The following unaudited pro forma information has been prepared assuming Gothic had been acquired as of the beginning of the period presented. The pro forma information is presented for information purposes only and is not necessarily indicative of what would have occurred if the acquisition had been made as of that date. In addition, the pro forma information is not intended to be a projection of future results and does not reflect any efficiencies that may result from the integration of Gothic.

PRO FORMA INFORMATION
(UNAUDITED)
($ IN THOUSANDS, EXCEPT PER SHARE DATA)

	2000
Revenues	$711,017
Income before income taxes	196,740
Net income	458,350
Earnings per common share-basic	3.27
Earnings per common share-assuming dilution	2.83

During 2001, we also completed a number of individually insignificant acquisitions, which totaled $316.7 million. During 2000 and 1999, we acquired working interests in proved oil and gas properties for total consideration of $78.9 million and $49.9 million, respectively. All of the acquisitions were accounted for using the purchase method and, accordingly, results of operations of these acquired entities and oil and gas properties have been included in Chesapeake's results of operations from the respective effective dates of acquisition.

From time to time, Chesapeake also invests in debt and equity securities of both private and public energy companies. During 2001, we purchased $17.4 million principal amount of RAM Energy, Inc. notes for $15.2 million, including accrued interest of $0.6 million. We later used $11.1 million principal amount of the RAM notes as a portion of the consideration for our purchase of oil and gas assets from RAM. Subsequent to year-end, we sold the remaining RAM notes for an amount that approximated their carrying value. In March 2001, we also purchased 49.5% of RAM's outstanding common stock for approximately $9.9 million. We sold the RAM common stock in December 2001 for minimal consideration, realizing a pre-tax loss of $8.6 million. In July 2001, we invested $22.5 million in 12% senior secured notes of Seven Seas Petroleum Inc. We intend to hold these notes to maturity, and thus carry them at amortized cost rather than market value. The Seven Seas notes we purchased were accompanied by seven-year warrants to purchase approximately 20.0% of Seven Seas' outstanding common stock on a fully diluted basis at an exercise price of $1.78 per share. We are carrying the warrants at allocated cost, which approximates fair value at year-end.

In October 2001, we sold Chesapeake Canada Corporation, a wholly-owned subsidiary, for net proceeds of approximately $143.0 million.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for 2000 and 2001 are as follows ($ in thousands except per share data):

	QUARTERS ENDED			
	MARCH 31, 2000	JUNE 30, 2000	SEPTEMBER 30, 2000	DECEMBER 31, 2000
Total Revenues	$ 114,661	$ 134,463	$168,182	$210,646
Gross profit(a)	40,975	53,142	76,918	107,734
Net income	21,202	31,634	54,689	348,045(b)
Net earnings per common share:				
Basic	0.27	0.26	0.33	2.28
Diluted	0.15	0.22	0.31	2.12

	QUARTERS ENDED			
	MARCH 31, 2001	JUNE 30, 2001	SEPTEMBER 30, 2001	DECEMBER 31, 2001
Total Revenues	$ 277,384	$ 275,681	$238,911	$177,075
Gross profit(a)	146,696	165,315	132,374	75,895
Net income	70,288	39,485(c)	65,008	42,625(d)
Net earnings per common share:				
Basic:				
Income before extraordinary item	0.44	0.52	0.40	0.25
Extraordinary item	--	(0.28)	--	--
Net Income	0.44	0.24	0.40	0.25
Diluted:				
Income before extraordinary item	0.41	0.50	0.38	0.23

Extraordinary item	--	(0.27)	--	--
Net Income	0.41	0.23	0.38	0.23

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(a) Total revenue less total operating costs.

(b) In the fourth quarter of 2000, we eliminated our valuation allowance resulting in the recognition of a $265 million income tax benefit. Based upon recent results of operations and anticipated improvement in Chesapeake's outlook for sustained profitability, we believed that it was more likely than not that we would generate sufficient future taxable income to realize the tax benefits associated with our NOL carryforwards prior to their expiration.

(c) Net of an extraordinary loss on extinguishment of debt of $46.0 million, net of income taxes.

(d) Includes pretax gain on sale of Canadian subsidiary of $27.0 million and pretax impairments of investments in securities of $10.1 million.

14. RECENT ACCOUNTING PRONOUNCEMENTS

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards Nos. 141 and 142. SFAS No. 141, Business Combinations, requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS No. 142, Goodwill and Other Intangible Assets, changes the accounting for goodwill from an amortization method to an impairment-only approach and will be effective January 2002. We believe that adoption of this new standard will not have an effect on our results of operations or our financial position. In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. We have not yet determined the effect of the adoption of SFAS No. 143 on our financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. SFAS 144 is effective for fiscal years beginning after December 15, 2002. This statement supersedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of, and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. We believe the future impact of the adoption of SFAS 144 on our financial position or results of operations will not be material.

SCHEDULE II

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
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, 1999:					
Allowance for doubtful accounts	$ 3,209	$ 9	$ --	$ --	$ 3,218
Valuation allowance for deferred tax assets	$458,903	$ --	$(5,931)(a)	$ 10,956	$442,016
December 31, 2000:					
Allowance for doubtful accounts	$ 3,218	$ 256	$ --	$ 2,389	$ 1,085
Valuation allowance for deferred tax assets	$442,016	$ --	$ --	$442,016(b)	$ --
December 31, 2001:					
Allowance for doubtful accounts	$ 1,085	$ 69	$ 44	$ 251	$ 947
Valuation allowance for deferred tax assets	$ --	$ 2,441(c)	$ --	$ --	$ 2,441

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(a) At December 31, 1998, $5.9 million of the valuation allowance was related to our Canadian deferred tax assets. During 1999, this valuation allowance was eliminated as part of a purchase price reallocation related to a 1998 acquisition.

(b) In the fourth quarter of 2000, we eliminated the valuation allowance for deferred tax assets. The reversal was based upon recent results of operations and anticipated improvements in Chesapeake's outlook for sustained profitability. During 2000, we revised our estimate of the 1999 U.S. net deferred tax asset and related valuation allowance from $442 million to $330 million as a result of further evaluation of the income tax basis of several acquisitions.

(c) At December 31, 2001, we determined that it was more likely than not that $2.4 million of the deferred tax assets related to Louisiana net operating losses will not be realized and we have recorded a valuation allowance equal to such amount.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2002.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2002.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2002.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by Chesapeake pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 30, 2002.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(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
2.1	--	Senior Secured Discount Notes Purchase Agreement dated June 23, 2000 between Chesapeake Energy Marketing, Inc. and Appaloosa Investment Limited Partnership I, Palomino Fund Ltd. and Tersk L.L.C. Incorporated herein by reference to Exhibit 2.1 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.2	--	Senior Secured Discount Notes Purchase Agreement dated June 23, 2000 between Chesapeake Energy Marketing, Inc. and Oppenheimer Strategic Income Fund, Oppenheimer Champion Income Fund, Oppenheimer High Yield Fund, Oppenheimer Strategic Bond Fund/VA and Atlas Strategic Income Fund. Incorporated herein by reference to Exhibit 2.2 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.3	--	Senior Secured Discount Notes Purchase Agreement dated June 26, 2000 between Chesapeake Energy Marketing, Inc. and John Hancock High Yield Bond Fund and John Hancock Variable Annuity High Yield Bond Fund. Incorporated herein by reference to Exhibit 2.3 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.4	--	Agreement and Plan of Merger dated September 8, 2000 among Chesapeake Energy Corporation, Chesapeake Merger 2000 Corp. and Gothic Energy Corporation, as amended by Amendment No. 1 to Agreement and Plan of Merger dated October 31, 2000. Incorporated by reference to Annex A to proxy statement/prospectus included in Amendment No. 1 to Registrant's registration statement on Form S-4 (No. 333-47330).
3.1	--	Registrant's Restated Certificate of Incorporation. Incorporated herein by reference to Exhibit 1 to Registrant's registration statement on Form 8-A filed February 15, 2002.
3.2	--	Registrant's Bylaws. Incorporated herein by reference to Exhibit 3.2 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2001.
4.1	--	Indenture dated as of March 15, 1997 among the Registrant, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 7.875% Senior Notes due 2004. Incorporated herein by reference to Exhibit 4.1 to Registrant's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on

EXHIBIT NUMBER		DESCRIPTION
		Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Ninth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
4.2	--	Indenture dated as of March 15, 1997 among the Registrant, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.3 to Registrant's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Ninth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
4.3	--	Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Supplemental Indenture dated May 14, 2001. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Second Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Third Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Fourth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
4.4	--	Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to 8.375% Senior Notes due 2008. Incorporated herein by reference to Exhibit 4.16 to Chesapeake's registration statement on Form S-4 (No. 333-74584). First Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.16.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
4.5	--	Agreement to furnish copies of unfiled long-term debt Instruments. Incorporated herein by reference to Registrant's transition report on Form 10-K for the six months ended December 31, 1997.
4.6	--	$225,000,000 Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and other

EXHIBIT NUMBER		DESCRIPTION
		lenders party thereto. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001. Consent and waiver letter dated September 10, 2001 and consent and waiver letter dated October 5, 2001. Incorporated herein by reference to Exhibits 4.6.1 and 4.6.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001, respectively. Consent and waiver letter dated November 2, 2001. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's registration statement on Form S-4 (No. 333-74584).
4.6.1*	--	First Amendment dated March 8, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.
4.9	--	Warrant Agreement dated as of September 9, 1997 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.9 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.10	--	Registration Rights Agreement dated as of September 9, 1997 among Gothic Energy Corporation, two of its subsidiaries, Oppenheimer & Co., Inc., Banc One Capital Corporation and Paribas Corporation. Incorporated herein by reference to Exhibit 4.10 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.11	--	Warrant Agreement dated as of January 23, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent. Incorporated herein by reference to Exhibit 4.11 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.12	--	Common Stock Registration Rights Agreement dated as of January 23, 1998 among Gothic Energy Corporation and purchasers of its senior redeemable preferred stock. Incorporated herein by reference to Exhibit 4.12 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.13	--	Substitute Warrant to Purchase Common Stock of Chesapeake Energy Corporation dated as of January 16, 2001 issued to Amoco Corporation. Incorporated herein by reference to Exhibit 4.13 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.14	--	Warrant Agreement dated as of April 21, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.14 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.15	--	Warrant Registration Rights Agreement dated as of April 21, 1998 among Gothic Energy Corporation and purchasers of units consisting of its 14 1/8% senior secured discount notes due 2006 and warrants to purchase its common stock. Incorporated herein by reference to Exhibit 4.15 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
10.1.1+	--	Registrant's 1992 Incentive Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.1 to Registrant's registration statement on Form S-4 (No. 33-93718).
10.1.2+	--	Registrant's 1992 Nonstatutory Stock Option Plan, as Amended. Incorporated herein by reference to Exhibit 10.1.2 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.3+	--	Registrant's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.4+	--	Registrant's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit B to Registrant's definitive proxy statement for its 1996 annual meeting of shareholders.

EXHIBIT NUMBER		DESCRIPTION
10.1.5+	--	Registrant's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.1.6+	--	Registrant's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.7+	--	Registrant's 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.8+	--	Registrant's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit B to Registrant's definitive proxy statement for its 2001 annual meeting of shareholders filed April 30, 2001.
10.1.9+	--	Registrant'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+	--	Registrant'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.
10.2.1+	--	Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.7 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.2+	--	Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.8 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.3+	--	Amended and Restated Employment Agreement dated as of August 1, 2000 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Registrant's registration statement on Form S-1 (No. 333-45872).
10.2.8+	--	Employment Agreement dated as of July 1, 2000 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.
10.2.9+	--	Employment Agreement dated as of July 1, 2000 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.9 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.
10.3+	--	Form of Indemnity Agreement for officers and directors of Registrant and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Registrant's registration statement on form S-1 (No. 33-55600).
10.4.1	--	Amended and Restated Consulting Agreement dated January 11, 2001 between Chesapeake Energy Corporation and Michael Paulk. Incorporated herein by reference to Exhibit 10.4.1 of Registrant's annual report on Form 10-K for the year ended December 31, 2000.
10.4.2	--	Amended and Restated Consulting Agreement dated January 11, 2001 between Chesapeake Energy Corporation and Steven P. Ensz. Incorporated herein by reference to Exhibit 10.4.2 of Registrant's annual report on Form 10-K for the year ended December 31, 2000.
10.5	--	Rights Agreement dated July 15, 1998 between the Registrant and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Registrant'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 Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

10.10	--	Partnership Agreement of Chesapeake Exploration Limited Partnership dated December 27, 1994 between Chesapeake Energy Corporation and Chesapeake Operating, Inc. Incorporated herein by reference to Exhibit 10.10 to Registrant's registration statement on Form S-4 (No. 33-93718).
10.11	--	Amended and Restated Limited Partnership Agreement of Chesapeake Louisiana, L.P. dated June 30, 1997 between Chesapeake Operating, Inc. and Chesapeake Energy Louisiana Corporation.
12*	--	Ratios of Earnings to Fixed Charges and Preferred Dividends.
21*	--	Subsidiaries of Registrant
23.1*	--	Consent of PricewaterhouseCoopers LLP
23.2*	--	Consent of Williamson Petroleum Consultants, Inc.
23.3*	--	Consent of Ryder Scott Company L.P.
23.4*	--	Consent of Lee Keeling and Associates, Inc.

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* Filed herewith.

+ Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K

During the quarter ended December 31, 2001, Chesapeake filed the following current reports on Form 8-K:

On October 3, 2001, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing the sale of our Canadian subsidiary, confirmation of hedge positions and $50 million stock buyback program.

On October 24, 2001, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing third quarter 2001 earnings release and conference call dates.

On October 25, 2001, we furnished a current report on Form 8-K reporting under Item 9 the posting on our web site of key operating assumptions and projections for the fourth quarter of 2001 and full year 2002.

On October 25, 2001 (and as amended on October 26, 2001), we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release reporting earnings of $0.38 per fully diluted share of the 2001 third quarter and furnishing under Item 9 certain forecasts that we made in such press release.

On October 29, 2001, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing the pricing on $250 million of 8.375% Senior Notes due 2008.

On November 1, 2001, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing the commencement of a private offering of 2.5 million shares of convertible preferred stock. We also reported under Item 5 the status of negotiations for certain acquisitions.

On November 2, 2001, we furnished a current report on Form 8-K reporting under Item 9 that we had posted a slide show presentation on our web site which was being presented to institutional investors in various meetings in the first week of November 2001.

On November 7, 2001, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing the pricing and the setting of terms on our $150 million of 6.75% Cumulative Convertible Preferred Stock.

On December 5, 2001, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing the purchase of proved gas reserves and daily gas production, hedging gains of $250 million and no hedging exposure with Enron. We furnished under Item 9, updates to our fourth quarter 2001 and full year 2002 forecasts and our posting of such forecasts on our web site.

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 28, 2002

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	TITLE	DATE
/s/ AUBREY K. McCLENDON Aubrey K. McClendon	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	
/s/ TOM L. WARD Tom L. Ward	President, Chief Operating Officer and Director (Principal Executive Officer)	
/s/ MARCUS C. ROWLAND Marcus C. Rowland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	
/s/ MICHAEL A. JOHNSON Michael A. Johnson	Senior Vice President - Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	
/s/ EDGAR F. HEIZER, JR. Edgar F. Heizer, Jr.	Director	
/s/ BREENE M. KERR Breene M. Kerr	Director	
/s/ SHANNON T. SELF Shannon T. Self	Director	
/s/ FREDERICK B. WHITTEMORE Frederick B. Whittemore	Director	

INDEX TO EXHIBITS

EXHIBIT NUMBER		DESCRIPTION
2.1	--	Senior Secured Discount Notes Purchase Agreement dated June 23, 2000 between Chesapeake Energy Marketing, Inc. and Appaloosa Investment Limited Partnership I, Palomino Fund Ltd. and Tersk L.L.C. Incorporated herein by reference to Exhibit 2.1 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.2	--	Senior Secured Discount Notes Purchase Agreement dated June 23, 2000 between Chesapeake Energy Marketing, Inc. and Oppenheimer Strategic Income Fund, Oppenheimer Champion Income Fund, Oppenheimer High Yield Fund, Oppenheimer Strategic Bond Fund/VA and Atlas Strategic Income Fund. Incorporated herein by reference to Exhibit 2.2 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.3	--	Senior Secured Discount Notes Purchase Agreement dated June 26, 2000 between Chesapeake Energy Marketing, Inc. and John Hancock High Yield Bond Fund and John Hancock Variable Annuity High Yield Bond Fund. Incorporated herein by reference to Exhibit 2.3 to Registrant's Form S-1 Registration Statement (No. 333-41014).
2.4	--	Agreement and Plan of Merger dated September 8, 2000 among Chesapeake Energy Corporation, Chesapeake Merger 2000 Corp. and Gothic Energy Corporation, as amended by Amendment No. 1 to Agreement and Plan of Merger dated October 31, 2000. Incorporated by reference to Annex A to proxy statement/prospectus included in Amendment No. 1 to Registrant's registration statement on Form S-4 (No. 333-47330).
3.1	--	Registrant's Restated Certificate of Incorporation. Incorporated herein by reference to Exhibit 1 to Registrant's registration statement on Form 8-A filed February 15, 2002.
3.2	--	Registrant's Bylaws. Incorporated herein by reference to Exhibit 3.2 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2001.
4.1	--	Indenture dated as of March 15, 1997 among the Registrant, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 7.875% Senior Notes due 2004. Incorporated herein by reference to Exhibit 4.1 to Registrant's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.1.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.1.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.1.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001.

EXHIBIT NUMBER		DESCRIPTION
		Ninth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.1.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
4.2	--	Indenture dated as of March 15, 1997 among the Registrant, as issuer, Chesapeake Operating, Inc., Chesapeake Gas Development Corporation and Chesapeake Exploration Limited Partnership, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.3 to Registrant's registration statement on Form S-4 (No. 333-24995). First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Second [Third] Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's registration statement on Form S-3 (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.2.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998. Fifth Supplemental Indenture dated November 19, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Sixth Supplemental Indenture dated December 31, 1999. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Seventh Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.2.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Eighth Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.2.3 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Ninth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.2.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
4.3	--	Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to 8.125% Senior Notes due 2011. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Supplemental Indenture dated May 14, 2001. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended March 31, 2001. Second Supplemental Indenture dated September 12, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Third Supplemental Indenture dated October 1, 2001. Incorporated herein by reference to Exhibit 4.3.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001. Fourth Supplemental Indenture dated December 17, 2001. Incorporated herein by reference to Exhibit 4.3.1 to Chesapeake's registration statement on Form S-3 (No. 333-76546).
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4.6	--	$225,000,000 Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation,

EXHIBIT NUMBER		DESCRIPTION
		Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and Toronto Dominion (Texas), Inc., as Co-Documentation Agents Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and other lenders party thereto. Incorporated herein by reference to Exhibit 4.6 to Chesapeake's quarterly report on Form 10-Q for the quarter ended June 30, 2001. Consent and waiver letter dated September 10, 2001 and consent and waiver letter dated October 5, 2001. Incorporated herein by reference to Exhibits 4.6.1 and 4.6.2 to Chesapeake's quarterly report on Form 10-Q for the quarter ended September 30, 2001, respectively. Consent and waiver letter dated November 2, 2001. Incorporated herein by reference to Exhibit 4.6.1 to Chesapeake's registration statement on Form S-4 (No. 333-74584).
4.6.1*	--	First Amendment dated March 8, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.
4.9	--	Warrant Agreement dated as of September 9, 1997 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.9 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.10	--	Registration Rights Agreement dated as of September 9, 1997 among Gothic Energy Corporation, two of its subsidiaries, Oppenheimer & Co., Inc., Banc One Capital Corporation and Paribas Corporation. Incorporated herein by reference to Exhibit 4.10 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.11	--	Warrant Agreement dated as of January 23, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent. Incorporated herein by reference to Exhibit 4.11 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.12	--	Common Stock Registration Rights Agreement dated as of January 23, 1998 among Gothic Energy Corporation and purchasers of its senior redeemable preferred stock. Incorporated herein by reference to Exhibit 4.12 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.13	--	Substitute Warrant to Purchase Common Stock of Chesapeake Energy Corporation dated as of January 16, 2001 issued to Amoco Corporation. Incorporated herein by reference to Exhibit 4.13 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.14	--	Warrant Agreement dated as of April 21, 1998 between Gothic Energy Corporation and American Stock Transfer & Trust Company, as warrant agent, and Supplement to Warrant Agreement dated as of January 16, 2001. Incorporated herein by reference to Exhibit 4.14 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
4.15	--	Warrant Registration Rights Agreement dated as of April 21, 1998 among Gothic Energy Corporation and purchasers of units consisting of its 14 1/8% senior secured discount notes due 2006 and warrants to purchase its common stock. Incorporated herein by reference to Exhibit 4.15 to registrant's annual report on Form 10-K for the year ended December 31, 2000.
10.1.1+	--	Registrant's 1992 Incentive Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.1 to Registrant's registration statement on Form S-4 (No. 33-93718).

EXHIBIT NUMBER		DESCRIPTION
10.1.2+	--	Registrant's 1992 Nonstatutory Stock Option Plan, as Amended. Incorporated herein by reference to Exhibit 10.1.2 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.3+	--	Registrant's 1994 Stock Option Plan, as amended. Incorporated herein by reference to Exhibit 10.1.3 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
10.1.4+	--	Registrant's 1996 Stock Option Plan. Incorporated herein by reference to Exhibit B to Registrant's definitive proxy statement for its 1996 annual meeting of shareholders .
10.1.5+	--	Registrant's 1999 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.5 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.1.6+	--	Registrant's 2000 Employee Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.6 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.7+	--	Registrant's 2000 Executive Officer Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.7 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 2000.
10.1.8+	--	Registrant's 2001 Stock Option Plan. Incorporated herein by reference to Exhibit B to Registrant's definitive proxy statement for its 2001 annual meeting of shareholders filed April 30, 2001.
10.1.9+	--	Registrant'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+	--	Registrant'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.
10.2.1+	--	Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.7 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.2+	--	Second Amended and Restated Employment Agreement dated as of July 1, 2001, between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 4.8 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 2001.
10.2.3+	--	Amended and Restated Employment Agreement dated as of August 1, 2000 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Registrant's registration statement on Form S-1 (No. 333-45872).
10.2.8+	--	Employment Agreement dated as of July 1, 2000 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.
10.2.9+	--	Employment Agreement dated as of July 1, 2000 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.9 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 2000.
10.3+	--	Form of Indemnity Agreement for officers and directors of Registrant and its subsidiaries. Incorporated herein by reference to Exhibit 10.30 to Registrant's registration statement on form S-1 (No. 33-55600).

EXHIBIT NUMBER		DESCRIPTION
10.4.1	--	Amended and Restated Consulting Agreement dated January 11, 2001 between Chesapeake Energy Corporation and Michael Paulk. Incorporated herein by reference to Exhibit 10.4.1 of Registrant's annual report on Form 10-K for the year ended December 31, 2000.
10.4.2	--	Amended and Restated Consulting Agreement dated January 11, 2001 between Chesapeake Energy Corporation and Steven P. Ensz. Incorporated herein by reference to Exhibit 10.4.2 of Registrant's annual report on Form 10-K for the year ended December 31, 2000.
10.5	--	Rights Agreement dated July 15, 1998 between the Registrant and UMB Bank, N.A., as Rights Agent. Incorporated herein by reference to Exhibit 1 to Registrant'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 Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
10.10	--	Partnership Agreement of Chesapeake Exploration Limited Partnership dated December 27, 1994 between Chesapeake Energy Corporation and Chesapeake Operating, Inc. Incorporated herein by reference to Exhibit 10.10 to Registrant's registration statement on Form S-4 (No. 33-93718).
10.11	--	Amended and Restated Limited Partnership Agreement of Chesapeake Louisiana, L.P. dated June 30, 1997 between Chesapeake Operating, Inc. and Chesapeake Energy Louisiana Corporation.
12*	--	Ratios of Earnings to Fixed Charges and Preferred Dividends.
21*	--	Subsidiaries of Registrant
23.1*	--	Consent of PricewaterhouseCoopers LLP
23.2*	--	Consent of Williamson Petroleum Consultants, Inc.
23.3*	--	Consent of Ryder Scott Company L.P.
23.4*	--	Consent of Lee Keeling and Associates, Inc.

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* Filed herewith.

+ Management contract or compensatory plan or arrangement.

EXHIBIT 4.6.1

FIRST AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT

THIS FIRST AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT (herein called the "Amendment") made as of March 8, 2002 by and among Chesapeake Exploration Limited Partnership, an Oklahoma limited partnership ("Borrower"), Chesapeake Energy Corporation, an Oklahoma corporation ("Company"), Bear Stearns Corporate Lending Inc., as syndication agent ("Syndication Agent"), Union Bank of California, N.A., as administrative agent and collateral agent ("Administrative Agent"), and the several banks and other financial institutions or entities parties thereto ("Lenders").

WITNESSETH:

WHEREAS, Borrower, Company, Syndication Agent, Administrative Agent and Lenders entered into that certain Second Amended and Restated Credit Agreement dated as of June 11, 2001 (as amended, supplemented, or restated to the date hereof, the "Original Agreement"), for the purpose and consideration therein expressed, whereby Lenders became obligated to make loans to Borrower as therein provided; and

WHEREAS, Borrower, Company, Syndication Agent, Administrative Agent and Lenders desire to amend the Original Agreement as set forth herein;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements contained herein and in the Original Agreement, in consideration of the loans which may hereafter be made by Lenders to Borrower, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto do hereby agree as follows:

ARTICLE I.

Definitions and References

Section 1.1. Terms Defined in the Original Agreement. Unless the context otherwise requires or unless otherwise expressly defined herein, the terms defined in the Original Agreement shall have the same meanings whenever used in this Amendment.

Section 1.2. Other Defined Terms. Unless the context otherwise requires, the following terms when used in this Amendment shall have the meanings assigned to them in this Section 1.2.

"Amendment" means this First Amendment to Second Amended and Restated Credit Agreement.

"Credit Agreement" means the Original Agreement as amended hereby.

ARTICLE II.

Amendments and Waivers

Section 2.1. Defined Terms.

(a) The definition of "Senior Debt Limit Reporting Event" in Section 1.1 of the Original Agreement is hereby deleted in its entirety. The following definitions in Section 1.1 of the Original Agreement are hereby amended in their entirety to read as follows:

> " 'Indentures': the collective reference to (i) the 7-7/8% Note Indenture, (ii) the 8-1/2% Note Indenture, (iii) the 8-1/8% Note Indenture and (iv) the 8-3/8% Note Indenture."

> " 'Senior Debt Limit': at any time the lesser of: (a) the maximum amount of Indebtedness that the Company and its Subsidiaries may incur and secure pursuant to the terms of clause (i) of the definition of "Permitted Indebtedness" and clause (ii) of the definition of "Permitted Liens" under the 8-1/8% Note Indenture and the 8-3/8% Note Indenture, minus the amount of Indebtedness (other than Indebtedness under this Agreement) that the Company or any of its Subsidiaries have incurred and/or secured by Liens as of such day that counts against the restrictions on the maximum amount of Indebtedness referred to in such clause (i); and (b) the sum of (x) the maximum amount of Indebtedness that the Company and its Subsidiaries may incur and secure pursuant to the terms of clause (i) of Section 4.9 of the 8-1/2% Note Indenture and the 7-7/8% Note Indenture minus the amount of Indebtedness (other than Indebtedness under this Agreement) that the Company or any of its Subsidiaries have incurred and/or secured by Liens as of such day that counts against the restrictions on the maximum amount of Indebtedness referred to in such clause (i) plus (y) the actual amount of Indebtedness, if any, incurred and secured by the Borrower under this Agreement which is permitted to be so incurred and secured under clause (b) of Section 4.9 of the 8-1/2% Note Indenture and the 7-7/8% Note Indenture. For purposes of this definition, (a) the amount under clause (b)(y) shall be determined by the Company pursuant to the 8-1/2% Note Indenture and the 7-7/8% Note Indenture, unless determined at another amount in the discretion of Administrative Agent or Majority Lenders, and (b) the term 'Indebtedness' shall have the meaning given in the 8-1/8% Note Indenture, the 8-3/8% Note Indenture, the 8-1/2% Note Indenture or the 7-7/8% Note Indenture, as applicable."

(b) Section 1.1 of the Original Agreement is hereby amended to add the following defined terms thereto in appropriate alphabetical order to read as follows:

" '8-3/8% Note Indenture': the Indenture, dated as of November 5, 2001, among the Company, certain subsidiary guarantors and The Bank of New York, as Trustee, pursuant to which the 8-3/8% Notes were issued."

" '8-3/8% Notes': the 8-3/8% senior notes of the Company due 2008."

Section 2.2. Conditions to Each Extension of Credit. Subsection (c) of Section 5.2 of the Original Agreement is hereby amended in its entirety to read as follows:

"(c) Senior Debt Limit. Administrative Agent shall have received a certificate dated as of the date of any extension of credit (the "Senior Debt Certificate") of the chief financial officer or treasurer of the Company certifying: (a) the maximum amount of Indebtedness that the Company and its Subsidiaries may incur and secure pursuant to the terms of clause (i) of the definition of "Permitted Indebtedness" and clause (ii) of the definition of "Permitted Liens" under the 8-1/8% Note Indenture and the 8-3/8% Note Indenture, and the amount, if any, of Indebtedness (other than Indebtedness under this Agreement) that the Company or any of its Subsidiaries have incurred and/or secured by Liens as of such day that counts against the restrictions on the maximum amount of Indebtedness referred to in such clause (i); and (b) (x) the maximum amount of Indebtedness that the Company and its Subsidiaries may incur and secure pursuant to the terms of clause (i) of Section 4.9 of the 8-1/2% Note Indenture and the 7-7/8% Note Indenture and the amount of Indebtedness (other than Indebtedness under this Agreement) that the Company or any of its Subsidiaries have incurred and/or secured by Liens as of such day that counts against the restrictions on the maximum amount of Indebtedness referred to in such clause (i) and (y) the actual amount of Indebtedness, if any, incurred and secured by the Borrower under this Agreement which is permitted to be so incurred and secured under clause (b) of Section 4.9 of the 8-1/2% Note Indenture and the 7-7/8% Note Indenture. Each Senior Debt Certificate shall attach documentation demonstrating compliance with the Senior Debt Limit as may be requested by Administrative Agent, including satisfactory reports and appraisals supporting such calculation and copies of the reports and appraisals prepared by independent petroleum engineers and appraisers in connection with the determination of Adjusted Consolidated Net Tangible Assets pursuant to the Indentures as of the last day of the most recently ended fiscal year of the Company."

Section 2.3. Certificates; Other Information. Clause (D) of subsection (b) of Section 6.2 of the Original Agreement is hereby deleted in its entirety. Paragraph 6 of the Compliance Certificate is hereby deleted in its entirety.

Section 2.4. Indebtedness. Section 7.2 of the Original Agreement is hereby amended by (a) deleting "and" at the end of subsection (j), (b) redesignating existing subsection "(k)" as subsection "(l)", and (c) adding an amended subsection (k) to read as follows:

"(k) Hedging Agreements entered into by the Company with the purpose and effect of contracting for variable interest rates on a principal amount of Indebtedness of the Company (which, for purposes of this subsection only, shall include the liquidation preference on preferred stock of the Company) that is accruing interest or dividends at a fixed rate, provided that (1) the ratio of fixed rate Indebtedness of the Company to total Indebtedness of the Company remains at least seventy percent (70%), and (2) each such contract is with a counterparty or has a guarantor of the obligation of the counterparty who (unless such counterparty is a Lender or one of its Affiliates) is a nationally recognized well capitalized hedging counterparty or is an investment grade industry participant; plus the Guarantee Obligations of one or more of the Group Members of the obligations of the Company permitted to be incurred under this Section 7.1(k)."

Section 2.5. Regarding Certain Subsidiaries. The Company and the Borrower hereby represent and warrant to Lenders and Administrative Agent that Carmen Acquisition Corp. is no longer an Unrestricted Subsidiary under the 8-1/2% Note Indenture and agree, contemporaneously herewith, that they will, and will cause Carmen Acquisition Corp. to, comply with the provisions of Section 6.9(b) of the Credit Agreement. The Company and the Borrower hereby represent and warrant to Lenders and Administrative Agent that Arkoma Pittsburg Holding Corporation has been merged with and into Borrower.

ARTICLE III.

Conditions of Effectiveness

Section 3.1. Effective Date. This Amendment shall become effective as of the date first above written when and only when:

(a) Administrative Agent shall have received all of the following, at Administrative Agent's office, duly executed and delivered and in form and substance satisfactory to Administrative Agent, all of the following:

(i) the Amendment;

(ii) a favorable opinion of Commercial Law Group, counsel for the Company, Borrower and the Subsidiary Guarantors, substantially in the form set forth in Exhibit F of the Original Agreement;

(iii) an "Omnibus Certificate" of the Secretary and of the Chairman of the Board or President of the general partner of Borrower, which shall contain the names and signatures of the officers of the general partner of Borrower authorized to execute Loan Documents and which shall certify to the truth, correctness and completeness of the following exhibits attached thereto: (1) a copy of resolutions attached thereto duly adopted by the Board of Directors of the general partner of Borrower and in full force and effect at the time this Amendment is entered into, authorizing the execution of this Amendment and the other Loan Documents delivered or to be delivered in connection herewith and the consummation of the transactions contemplated herein and therein, (2) a copy of the charter documents of Borrower and of the general partner of Borrower and all amendments thereto, certified by the appropriate official of the Borrower's state and general partner's state of organization, and (3) a copy of any bylaws of the general partner of Borrower previously delivered to Agent and Lenders in connection with the Original Agreement (which may, with respect to any such charter documents or bylaws, reference documents previously delivered in connection with the Original Agreement);

(iv) a "Compliance Certificate" of the Chairman of the Board or President and of the chief financial officer of the Company, in which such officers certify to the satisfaction of the conditions set out in subsections (a), (b), and (c) of Section 5.2 of the Original Agreement;

(v) documents similar to those specified in subsection (iii) of this Section with respect to each Subsidiary Guarantor (which may, with respect to charter documents or bylaws, reference documents previously delivered in connection with the Original Agreement);

(vi) a certificate executed by the chief financial officer of the Company of even date herewith reflecting the computation of the then current Senior Debt Limit together with supporting information satisfactory to Administrative Agent.

(vii) such other supporting documents as Administrative Agent may reasonably request.

(b) Borrower shall have paid, in connection with such Loan Documents, all recording, handling, amendment and other fees required to be paid to Administrative Agent pursuant to any Loan Documents.

(c) Borrower shall have paid, in connection with such Loan Documents, all other fees and reimbursements to be paid to Administrative Agent pursuant to any Loan Documents, or otherwise due Administrative Agent and including fees and disbursements of Administrative Agent's attorneys.

ARTICLE IV.

Representations and Warranties

Section 4.1. Representations and Warranties of Borrower. In order to induce each Lender to enter into this Amendment, Borrower represents and warrants to each Lender that:

(a) The representations and warranties contained in Section 4 of the Original Agreement are true and correct at and as of the time of the effectiveness hereof, except to the extent that the facts on which such representations and warranties are based have been changed by the extension of credit under the Credit Agreement.

(b) The Company and Borrower are duly authorized to execute and deliver this Amendment and are and will continue to be duly authorized to borrow monies and to perform their respective obligations under the Credit Agreement. The Company and Borrower have duly taken all corporate or partnership action necessary to authorize the execution and delivery of this Amendment and to authorize the performance of the obligations of the Company and Borrower hereunder.

(c) The execution and delivery by the Company and Borrower of this Amendment, the performance by the Company and Borrower of its obligations hereunder and the consummation of the transactions contemplated hereby do not and will not conflict with any provision of law, statute, rule or regulation or of the certificate of incorporation, bylaws, or agreement of limited partnership of the Company or Borrower (as applicable), or of any material agreement, judgment, license, order or permit applicable to or binding upon the Company or Borrower, or result in the creation of any lien, charge or encumbrance upon any assets or properties of the Company or Borrower. Except for those which have been obtained, no consent, approval, authorization or order of any court or governmental authority or third party is required in connection with the execution and delivery by the Company and Borrower of this Amendment or to consummate the transactions contemplated hereby.

(d) When duly executed and delivered, each of this Amendment and the Credit Agreement will be a legal and binding obligation of the Company and Borrower, enforceable in accordance with its terms, except as limited by bankruptcy, insolvency or similar laws of general application relating to the enforcement of creditors' rights and by equitable principles of general application.

(e) The audited annual Consolidated financial statements of the Company dated as of December 31, 2000 and the unaudited quarterly Consolidated financial statements of the Company dated as of September 30, 2001 fairly present the Consolidated financial position at such dates and the Consolidated statement of operations and the changes in Consolidated financial position for the periods ending on such dates for the Company. Copies of such financial statements have heretofore been delivered to each Lender. Since such dates no material adverse change has occurred in the financial condition or businesses or in the Consolidated financial condition or businesses of the Company.

ARTICLE V.

Miscellaneous

Section 5.1. Ratification of Agreements. The Original Agreement as hereby amended is hereby ratified and confirmed in all respects. Any reference to the Credit Agreement in any Loan Document shall be deemed to be a reference to the Original Agreement as hereby amended. The execution, delivery and effectiveness of this Amendment shall not, except as expressly provided herein, operate as a waiver of any right, power or remedy of Lenders under the Credit Agreement, the Notes, or any other Loan Document nor constitute a waiver of any provision of the Credit Agreement, the Notes or any other Loan Document.

Section 5.2. Survival of Agreements. All representations, warranties, covenants and agreements of Borrower herein shall survive the execution and delivery of this Amendment and the performance hereof, including without limitation the making or granting of the Loans, and shall further survive until all of the Obligations are paid in full. All statements and agreements contained in any certificate or instrument delivered by the Company, Borrower or any Subsidiary Guarantor hereunder or under the Credit Agreement to any Lender shall be deemed to constitute representations and warranties by, and/or agreements and covenants of, Borrower under this Amendment and under the Credit Agreement.

Section 5.3. Loan Documents. This Amendment is a Loan Document, and all provisions in the Credit Agreement pertaining to Loan Documents apply hereto.

Section 5.4. Governing Law. This Amendment shall be governed by and construed in accordance the laws of the State of New York and any applicable laws of the United States of America in all respects, including construction, validity and performance.

Section 5.5. Counterparts; Fax. This Amendment may be separately executed in counterparts and by the different parties hereto in separate counterparts, each of which when so executed shall be deemed to constitute one and the same Amendment. This Amendment may be validly executed by facsimile or other electronic transmission.

THIS AMENDMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS OF THE PARTIES.

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IN WITNESS WHEREOF, this Amendment is executed as of the date first above written.

CHESAPEAKE EXPLORATION LIMITED PARTNERSHIP

By: Chesapeake Operating, Inc., its general partner

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE ENERGY CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

UNION BANK OF CALIFORNIA, N.A.
Administrative Agent, Collateral Agent,
Issuing Lender and Lender

By: /s/ RANDALL OSTERBERG

Name: Randall Osterberg
Title: Vice President

By: /s/ SEAN MURPHY

Name: Sean Murphy
Title: Assistant Vice President

BANK OF OKLAHOMA, N.A.

By: /s/ JOHN N. HUFF

Name: John N. Huff
Title: Vice President

BANK OF SCOTLAND

By: /s/ JOSEPH FRATUS

Name: Joseph Fratus
Title: Vice President

BEAR STEARNS CORPORATE LENDING INC.

By: /s/ VICTOR BULZACCHELLI

Name: Victor Bulzacchelli
Title: Vice President

BNP PARIBAS

By: /s/ BETSY JOCHER /S/ J. ONISCHUK

Name: Betsy Jocher J. Onischuk
Title: Vice President Director

COMERICA BANK - TEXAS

By: /s/ PETER L. SEFZIK

Name: Peter L. Sefzik
Title: Corporate Banking Officer

COMPASS BANK

By: /s/ KATHLEEN J. BOWEN

Name: Kathleen J. Bowen
Title: Vice President

CREDIT AGRICOLE INDOSUEZ

By:

Name:
Title:

NATEXIS BANQUES POPULAIRES

/s/ RENAUD J. D'HERBES
- -------------------------
Renaud J. d'Herbes
Senior Vice President and
Regional Manager

By: /s/ DONOVAN C. BROUSSARD

Name: Donovan C. Broussard
Title: Vice President

PNC BANK, NATIONAL ASSOCIATION

By: /s/ DOUG CLARK

Name: Doug Clark
Title: Vice President

RZB FINANCE LLC

By:

Name:
Title:

By:

Name:
Title:

SUMITOMO MITSUI BANKING
CORPORATION

By:

Name:
Title:

TORONTO DOMINION (TEXAS), INC.

By: /s/ CAROL BRANDT

Name: Carol Brandt
Title: Vice President

U.S. BANK NATIONAL ASSOCIATION

By: /s/ MARK E. THOMPSON

Name: Mark E. Thompson
Title: Vice President

WASHINGTON MUTUAL BANK, FA

By: /s/ MARK M. ISENSEE

Name: Mark M. Isensee
Title:

CREDIT LYONNAIS NEW YORK BRANCH

By:

Name:
Title:

CONSENT AND AGREEMENT

By its execution below, each Guarantor hereby (i) consents to the provisions of this Amendment and the transactions contemplated herein, (ii) ratifies and confirms the Guarantee Agreement dated as of June 11, 2001 made by it for the benefit of Administrative Agent and Lenders and the other Loan Documents executed pursuant to the Credit Agreement (Carmen Acquisition Corp. and Sap Acquisition Corp. having become parties thereto by execution and delivery of that certain Assumption Agreement of even date herewith), (iii) agrees that all of its respective obligations and covenants thereunder shall remain unimpaired by the execution and delivery of this Amendment and the other documents and instruments executed in connection herewith, and (iv) agrees that the Guarantee Agreement and such other Loan Documents shall remain in full force and effect.

CHESAPEAKE ENERGY CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

THE AMES COMPANY, INC.

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE ACQUISITION CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE ENERGY LOUISIANA CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE OPERATING, INC.

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE PANHANDLE LIMITED PARTNERSHIP
By: CHESAPEAKE OPERATING, INC., its General Partner

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE ROYALTY COMPANY

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE-STAGHORN ACQUISITION L .P.
By: CHESAPEAKE OPERATING, INC., its General Partner

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CHESAPEAKE LOUISIANA, L.P.
By: CHESAPEAKE OPERATING, INC., its General Partner

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

GOTHIC ENERGY CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

GOTHIC PRODUCTION CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

NOMAC DRILLING CORPORATION

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

CARMEN ACQUSITION CORP.

By: /s/ MARTHA A. BURGER

Name: Martha A. Burger
Title: Treasurer

SAP ACQUISITION CORP.

By: /s/ MARTHA A. BURGER

    Name: Martha A. Burger
    Title: Treasurer

CHESAPEAKE MOUNTAIN FRONT CORP.

By: /s/ MARTHA A. BURGER

    Name: Martha A. Burger
    Title: Treasurer

EXHIBIT 12

CHESAPEAKE ENERGY CORPORATION
RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED DIVIDENDS
(IN 000'S)

	Year Ended June 30, 1997	Six Months Ended Dec. 31, 1997	Year Ended Dec. 31, 1998	Year Ended Dec. 31, 1999	Year Ended Dec. 31, 2000	Year Ended Dec. 31, 2001
Income before income taxes and extraordinary item	(180,330)	(31,574)	(920,520)	35,030	196,162	438,365
Interest	18,550	17,448	68,249	81,052	86,256	98,321
Amortization of capitalized interest	8,772	4,386	12,240	1,047	1,226	1,784
Bond discount amortization (a)		--				--
Loan cost amortization	1,455	794	2,516	3,338	3,669	4,022
Earnings	(151,553)	(8,946)	(837,515)	120,467	287,313	542,492
Interest expense	18,550	17,448	68,249	81,052	86,256	98,321
Capitalized interest	12,935	5,087	6,470	3,356	2,452	4,719
Preferred Stock Dividends						--
Pref. Dividend Requirements	--	--	12,077	16,711	8,484	2,050
Ratio of income before provision for taxes to Net Income (b)	--	--	N/A	1.05	N/A	1.66
Subtotal - Preferred Dividends	--	--	12,077	17,597	8,484	3,411
Bond discount amortization (a)		--	--	--	--	--
Loan cost amortization	1,455	794	2,516	3,338	3,669	4,022
Combined Fixed Charges and Preferred Dividends	32,940	23,329	89,312	105,343	100,861	110,473
Ratio	(4.6)	(0.4)	(9.4)	1.1	2.8	4.9
Insufficient coverage	184,493	32,275	926,827	--	--	--

(a) Bond discount excluded since it is included in interest expense.

(b) Represents income (loss) before income taxes and extraordinary item divided by income (loss) before extraordinary item, which adjusts dividends on preferred stock to a pre-tax basis.

EXHIBIT 21

CORPORATIONS	STATE OF ORGANIZATION
The Ames Company, Inc.	Oklahoma
Carmen Acquisition Corp.	Oklahoma
Chesapeake Acquisition Corporation	Oklahoma
Chesapeake Energy Louisiana Corporation	Oklahoma
Chesapeake Energy Marketing, Inc.	Oklahoma
Chesapeake Mountain Front Corp.	Oklahoma
Chesapeake Operating, Inc.	Oklahoma
Chesapeake Royalty Company	Oklahoma
CHK Acquisition, Inc.	Oklahoma
Gothic Energy Corporation	Oklahoma
Gothic Production Corporation	Oklahoma
Nomac Drilling Corporation	Oklahoma
Sap Acquisition Corp.	Oklahoma
PARTNERSHIPS	
Chesapeake Exploration Limited Partnership	Oklahoma
Chesapeake Louisiana, L.P.	Oklahoma
Chesapeake Panhandle Limited Partnership	Oklahoma
Chesapeake-Staghorn Acquisition L.P.	Oklahoma

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-07255, 333-30324, 333-46129, 333-30478, 333-52666, 333-52668, 333-67734, 333-67736, and 333-67740), Form S-3 (File Nos. 333-41014, 333-61508, and 333-76546) and Form S-4 (File Nos. 333-74584 and 333-74856) of Chesapeake Energy Corporation of our report dated March 8, 2002 relating to the consolidated financial statements and financial statement schedule, which appears in this Form 10-K.

PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma
March 27, 2002

EXHIBIT 23.2

[WILLIAMSON PETROLEUM CONSULTANTS, INC. LETTERHEAD]

CONSENT OF WILLIAMSON PETROLEUM CONSULTANTS, INC.

As independent oil and gas consultants, Williamson Petroleum Consultants, Inc. hereby consents to the use of our reserves report dated March 1, 2002 entitled "Evaluation of Oil and Gas Reserves to the Interests of Chesapeake Energy Corporation in Certain Major-Value Properties in the United States, Effective December 31, 2001, for Disclosure to the Securities and Exchange Commission, Williamson Project 1.8872" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K to be filed with the Securities and Exchange Commission on or about March 27, 2002.

/s/ WILLIAMSON PETROLEUM CONSULTANTS, INC.

WILLIAMSON PETROLEUM CONSULTANTS, INC.

Midland, Texas
March 26, 2002

EXHIBIT 23.3

[RYDER SCOTT COMPANY PETROLEUM CONSULTANTS LETTERHEAD]

CONSENT OF RYDER SCOTT COMPANY, L.P.

As independent oil and gas consultants, Ryder Scott Company, L.P. hereby consents to the incorporation by reference in this Form 10-K, to be filed with the Securities and Exchange Commission on or about March 27, 2002, of information from our reserve reports dated February 21, 2002, entitled "Estimated Future Reserves and Income Attributable to Certain leasehold Interests as of December 31, 2001" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended December 31, 2001. We also consent to the reference to us under the heading "Experts" in such 10-K.

/s/ RYDER SCOTT COMPANY, L.P.

RYDER SCOTT COMPANY, L.P.

Houston, Texas
March 27, 2002

EXHIBIT 23.4

[LEE KEELING AND ASSOCIATES, INC. LETTERHEAD]

CONSENT OF LEE KEELING AND ASSOCIATES, INC.

As independent oil and gas consultants, Lee Keeling and Associates, Inc. hereby consents to the incorporation by reference in this Form 10-K, to be filed with the Securities and Exchange Commission on or about March 27, 2002, of information from our reserve reports dated January 1, 2002, entitled "Appraisal Selected Properties" and all references to our firm included in or made a part of the Chesapeake Energy Corporation Annual Report on Form 10-K for the year ended December 31, 2001. We also consent to the reference to us under the heading "Experts" in such 10-K.

LEE KEELING AND ASSOCIATES, INC.

/s/ KENNETH RENBERG

Kenneth Renberg

Tulsa, Oklahoma
March 27, 2002