
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, 1999

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

COMMISSION FILE NO. 1-13726

CHESAPEAKE ENERGY CORPORATION
(Exact Name of Registrant as Specified in Its Charter)

OKLAHOMA	73-1395733
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6100 NORTH WESTERN AVENUE OKLAHOMA CITY, OKLAHOMA	73118
(Address of principal executive offices)	(Zip Code)

(405) 848-8000
Registrant's telephone number, including area code

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

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock, par value $.01	New York Stock Exchange
7.875% Senior Notes due 2004	New York Stock Exchange
9.625% Senior Notes due 2005	New York Stock Exchange
9.125% Senior Notes due 2006	New York Stock Exchange
8.5% Senior Notes due 2012	New York Stock Exchange
7% Cumulative Convertible Preferred Stock, par value $.01	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, 2000 was $214,958,367. At such date, there were 103,955,497 shares of Common Stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

PORTIONS OF THE REGISTRANT'S DEFINITIVE PROXY STATEMENT FOR THE 2000 ANNUAL MEETING OF SHAREHOLDERS ARE INCORPORATED BY REFERENCE IN PART III

PART I

ITEM 1. BUSINESS

GENERAL

Chesapeake Energy Corporation ("Chesapeake" or the "Company") is an independent oil and gas company engaged in the development, exploration, acquisition and production of onshore natural gas and oil reserves in the United States and Canada. Chesapeake began operations in 1989 and completed its initial public offering in 1993. Its common stock trades on the New York Stock Exchange under the symbol CHK. The Company's principal offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 (telephone 405/848-8000 and website address of chkenergy.com).

Chesapeake owns interests in approximately 4,700 producing oil and gas wells concentrated in three primary operating areas: the Mid-Continent region of Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle; the Gulf Coast region consisting primarily of the Austin Chalk Trend in Texas and Louisiana and the Tuscaloosa Trend in Louisiana; and the Helmet area of northeastern British Columbia. During 1999, the Company produced 133.5 Bcfe, making Chesapeake one of the 15 largest public independent oil and gas producers in the United States.

Business Strategy. From inception as a start-up in 1989 through today, Chesapeake's business strategy has been to aggressively build and develop one of the largest onshore natural gas resource bases in the U.S. The Company has executed its strategy through a combination of active drilling and acquisition programs during the past 10 years. Based on its view that natural gas will become the fuel of choice in the 21st century to meet growing power demand and increasing environmental concerns, Chesapeake believes its strategy will deliver attractive returns and substantial growth opportunities in the years ahead.

1999 Highlights. In the challenging oil and gas environment of 1999, the Company focused its efforts on drilling lower risk developmental wells, acquiring reserves at the lowest possible cost, divesting of higher cost and non-strategic properties and maintaining a capital expenditure budget closely tied to operating cash flow and proceeds from asset sales. Despite experiencing 20-year lows in oil and gas pricing during the first half of 1999, Chesapeake achieved considerable operating and financial progress during the year. Listed below are a few of Chesapeake's accomplishments in 1999 compared to 1998's results:

- net income of $33 million, compared to a net loss of $934 million
- cash flow from operations (before changes in working capital) of $139 million, an increase of 18%
- proved oil and gas reserves of 1,206 Bcfe, an increase of 11%
- oil and natural gas production of 133.5 Bcfe, an increase of 3%
- reserve replacement of 186% at a cost of $0.65 per Mcfe

In addition, Chesapeake's operating cost structure remained among the lowest of all publicly traded independent energy producers during 1999. The Company's per unit operating costs (consisting of general and administrative expenses, production expenses, production taxes, and depreciation, depletion and amortization of oil and gas properties) were $1.26 per Mcfe of production, resulting in an operating margin of $0.84 per Mcfe. The Company's low costs are attributable to its focus on developing highly productive natural gas properties, its efficient and motivated employees, and the successful integration of advanced drilling and completion expertise with its large inventory of undeveloped leasehold.

During 1999 and early 2000, Chesapeake was successful in defeating two material pieces of litigation against the Company. First, in the 1996 Union Pacific Resources Corporation patent infringement litigation involving horizontal drilling, the U.S. District Court in Ft. Worth dismissed the lawsuit, ruling in September 1999 that a patent previously granted to UPRC was invalid and therefore Chesapeake could not have infringed upon it. Second, in March 2000, the U.S. District Court in Oklahoma City dismissed a class action securities suit which had been pending against the Company since 1997.

2000 Outlook. Chesapeake's strategy remains unchanged for 2000: maintain a superior operating cost structure, fund a capital expenditure budget in balance with operating cash flow, and deliver attractive financial returns from its assets during a time of strengthening natural gas fundamentals.

DRILLING ACTIVITY

The following table sets forth the wells drilled by the Company during the periods indicated. In the table, "gross" refers to the total wells in which the Company has a working interest and "net" refers to gross wells multiplied by the Company's working interest therein.

	YEARS ENDED DECEMBER 31,				SIX MONTHS ENDED DECEMBER 31,		YEAR ENDED JUNE 30,	
	1999		1998		1997		1997	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
United States								
Development:								
Productive...........	167	93.3	158	93.9	55	24.4	90	55.0
Non-productive.......	17	10.6	9	4.7	1	0.3	2	0.2
Total................	184	103.9	167	98.6	56	24.7	92	55.2
Exploratory:								
Productive...........	9	3.7	46	23.4	28	15.5	71	46.1
Non-productive.......	6	4.6	9	6.8	2	0.9	8	5.7
Total................	15	8.3	55	30.2	30	16.4	79	51.8
Canada								
Development:								
Productive...........	11	7.3	11	3.6				
Non-productive.......	1	0.2	1	0.4				
Total................	12	7.5	12	4.0				
Exploratory:								
Productive...........	--	--	1	0.3				
Non-productive.......	--	--	7	2.1				
Total................	--	--	8	2.4				

WELL DATA

At December 31, 1999, the Company had interests in 4,719 (2,235.1 net) producing wells, of which 238 (104.6 net) were classified as primarily oil producing wells and 4,481 (2,130.5 net) were classified as primarily gas producing wells.

VOLUMES, REVENUE, PRICES AND PRODUCTION COSTS

The following table sets forth certain information regarding the production volumes, revenue, average prices received and average production costs associated with the Company's sale of oil and gas for the periods indicated:

	YEARS ENDED DECEMBER 31, 1999	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
NET PRODUCTION:				
Oil (MBbl)	4,147	5,976	1,857	2,770
Gas (MMcf)	108,610	94,421	27,326	62,005
Gas equivalent (MMcfe)	133,492	130,277	38,468	78,625
OIL AND GAS SALES ($ IN 000'S):				
Oil	$ 66,413	$ 75,877	$ 34,523	$ 57,974
Gas	214,032	181,010	61,134	134,946
Total oil and gas sales	$ 280,445	$ 256,887	$ 95,657	$ 192,920
AVERAGE SALES PRICE:				
Oil ($ per Bbl)	$ 16.01	$ 12.70	$ 18.59	$ 20.93
Gas ($ per Mcf)	$ 1.97	$ 1.92	$ 2.24	$ 2.18
Gas equivalent ($ per Mcfe)	$ 2.10	$ 1.97	$ 2.49	$ 2.45
OIL AND GAS COSTS ($ PER MCFE):				
Production expenses	$ .35	$ .39	$ .20	$ .14
Production taxes	$ .10	$ .06	$ .07	$ .05
General and administrative	$ .10	$ .15	$ .15	$ .11
Depreciation, depletion and amortization	$ .71	$ 1.13	$ 1.57	$ 1.31

Included in the above table are the results of Canadian operations during 1999 and 1998. The average sales price for the Company's Canadian gas production was $1.19 and $1.03 during 1999 and 1998, respectively, and the Canadian production expenses were $0.18 and $0.24 per Mcfe, respectively.

PROVED RESERVES

The following table sets forth the Company's estimated proved reserves and the present value (discounted at 10%) of the proved reserves (based on weighted average prices at December 31, 1999 of $24.72 per barrel of oil and $2.25 per Mcf of gas):

	OIL (MBBL)	GAS (MMCF)	GAS EQUIVALENT (MMCFE)	PERCENT OF PROVED RESERVES	PRESENT VALUE (DISC. @ 10%) ($ IN 000'S)
Mid-Continent	12,230	684,178	757,559	63%	$ 663,993
Gulf Coast	4,169	164,693	189,708	15	211,348
Canada	--	178,242	178,242	15	97,749
Other areas	8,396	29,713	80,086	7	116,406
Total	24,795	1,056,826	1,205,595	100%	$1,089,496

During 1999, Chesapeake increased its proved developed reserve percentage to 80% by present value and 72% by volume, and natural gas reserves accounted for 88% of proved reserves at December 31, 1999.

DEVELOPMENT, EXPLORATION AND ACQUISITION EXPENDITURES

The following table sets forth certain information regarding the costs incurred by the Company in its development, exploration and acquisition activities during the periods indicated:

	YEARS ENDED DECEMBER 31, 1999	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS)			
Development and leasehold costs	$ 126,865	$ 176,610	$ 144,283	$ 324,989
Exploration costs	23,693	68,672	40,534	136,473
Acquisition costs	52,093	740,280	39,245	--
Sales of oil and gas properties	(45,635)	(15,712)	--	--
Capitalized internal costs	2,710	5,262	2,435	3,905
Total	$ 159,726	$ 975,112	$ 226,497	$ 465,367

ACREAGE

The following table sets forth as of December 31, 1999 the gross and net acres of both developed and undeveloped oil and gas leases which the Company holds. "Gross" acres are the total number of acres in which the Company owns a working interest. "Net" acres refer to gross acres multiplied by the Company's fractional working interest. Acreage numbers are stated in thousands and do not include options for additional leasehold held by the Company, but not yet exercised.

	DEVELOPED		UNDEVELOPED		TOTAL DEVELOPED AND UNDEVELOPED	
	GROSS	NET	GROSS	NET	GROSS	NET
Mid-Continent	1,439	563	848	306	2,287	869
Gulf Coast	230	156	766	666	996	822
Canada	100	50	641	305	741	355
Other areas	40	21	639	421	679	442
Total	1,809	790	2,894	1,698	4,703	2,488

MARKETING

The Company's oil production is sold under market sensitive or spot price contracts. The Company's natural gas production is sold to purchasers under varying 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, the Company receives a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after gathering and processing the Company's gas. The residue gas and natural gas liquids sold by these purchasers are sold primarily based on spot market prices. The revenue received by the Company from the sale of natural gas liquids is included in natural gas sales. During 1999, only sales to Aquila Southwest Pipeline Corporation of $31.5 million accounted for more than 10% of the Company's total oil and gas sales. Management believes that the loss of this customer would not have a material adverse effect on the Company's results of operations or its financial position.

Chesapeake Energy Marketing, Inc. ("CEMI"), a wholly-owned subsidiary, provides oil and natural gas marketing services, including commodity price structuring, contract administration and nomination services for the Company, its partners and other oil and natural gas producers in certain geographical areas in which the Company is active.

HEDGING ACTIVITIES

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production and to manage fixed interest rate exposure. See Item 7A - Quantitative and Qualitative Disclosures About Market Risk.

RISK FACTORS

Substantial Debt Levels Could Affect Operations.

As of December 31, 1999, we had long-term indebtedness of $964.1 million (which included bank indebtedness of $43.5 million) and stockholders' equity was a deficit of $217.5 million. Our ability to meet our debt service requirements throughout the life of the senior notes and our ability to meet our preferred stock obligations will depend on our future performance, which will be subject to oil and gas prices, our production levels of oil and gas, general economic conditions, and various financial, business and other factors affecting our operations. Our level of indebtedness may have the following effects on future operations:

- a substantial portion of our cash flow from operations may be dedicated to the payment of interest on indebtedness and will not be available for other purposes,

- restrictions in our debt instruments limit our ability to borrow additional funds or to dispose of assets and may affect our flexibility in planning for, and reacting to, changes in the energy industry, and

- our ability to obtain additional capital in the future may be impaired.

As a result of our high level of indebtedness and poor conditions in the energy industry, Standard & Poor's Corporation and Moody's Investors Service reduced the credit ratings on our senior notes to "B" and "B3", respectively, in late 1998. These ratings were removed from credit review in 1999. Our credit ratings could negatively impact our ability to access capital markets.

The Volatility of Oil and Gas Prices Creates Uncertainties.

Our revenues, operating results and future rate of growth are highly dependent on the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and may continue to be volatile in the future. Various factors which are beyond our control will affect prices of oil and gas. These factors include:

- worldwide and domestic supplies of oil and gas,

- weather conditions,

- 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,

- the price and level of foreign imports,

- the level of consumer demand,

- the price and availability of alternative fuels,

- the availability of pipeline capacity, and

- domestic and foreign governmental regulations and taxes.

We are unable to predict the long-term effects of these and other conditions on the prices of oil and gas. Lower oil and gas prices may reduce the amount of oil and gas we produce, which may adversely affect our revenues and operating income. Because in 2000 we plan to match as nearly as possible our capital expenditures for drilling and acquisition activities to cash flow from operations, significant reductions in oil and gas prices may require us to reduce our capital expenditures. Reducing drilling will make it more difficult for us to replace the reserves we produce.

We Must Replace Reserves to Sustain Production.

As is customary in the oil and gas exploration and production industry, 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. In addition, approximately 28% by volume, or 20% by value, of our total estimated proved reserves at December 31, 1999 were undeveloped. By their nature, undeveloped reserves are less certain. 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.

Significant Capital Expenditures Will be Required to Exploit Reserves.

We have made and intend to make substantial capital expenditures in connection with the exploration, development and production of our oil and gas properties. Historically, we have funded our capital expenditures through a combination of internally generated funds, equity issuances and long-term debt financing arrangements and sale of non-core assets. From time to time, we have used short-term bank debt, generally as a working capital facility. 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 and in selling non-core assets. 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 debt or equity financing will be available to meet these requirements.

We May Have Full-Cost Ceiling Writedowns if Oil and Gas Prices Decline or if Drilling Results are Unfavorable.

We reported full-cost ceiling writedowns of $826 million, $110 million, and $236 million during the year ended December 31, 1998, the six-month transition period ended December 31, 1997 (the "Transition Period"), and the year ended June 30, 1997 ("fiscal 1997"), respectively. These writedowns were caused by significant declines in oil and gas prices during all three periods and by poor drilling results in fiscal 1997 and during the Transition Period. Additionally, significant declines in prices can cause proved undeveloped reserves to become uneconomic, and long-lived production to become "economically truncated", further reducing proved reserves and increasing any writedown. Our reserve values were calculated using weighted average prices at December 31, 1999 of $24.72 per barrel of oil and $2.25 per Mcf of natural gas. If prices in future periods are below the prices of $10.48 per barrel of oil and $1.68 per mcf of natural gas used at December 31, 1998, the last period during which Chesapeake recorded an impairment to its oil and gas properties, future impairment charges could be incurred. Although we have taken steps to reduce drilling risk, reduce operating costs, and reduce investment in unproved leasehold, these steps may not be sufficient to enhance future economic results or prevent additional leasehold impairment and full-cost ceiling writedowns, which are highly dependent on future oil and gas prices.

Drilling and Oil and Gas Operations Present Unique Risks.

Drilling activities are subject to many risks, including well blowouts, cratering, uncontrollable flows of oil, natural gas or well fluids, fires, formations with abnormal pressures, pollution, releases of toxic gases and other environmental hazards and risk, any of which could result in substantial losses. In addition, we incur the risk that we will not encounter any commercially productive reservoirs through our drilling operations. We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment in wells drilled. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs.

Existing Debt Covenants Restrict Our Operations.

The indentures which govern our senior notes contain covenants which restrict our ability, and the ability of our subsidiaries other than CEMI, to engage in the following activities:

- incurring additional debt,
- creating liens,
- paying dividends and making other restricted payments,
- merging or consolidating with any other entity,
- selling, assigning, transferring, leasing or otherwise disposing of all or substantially all of our assets, and
- guaranteeing indebtedness.

At December 31, 1999, we did not meet a debt incurrence test contained in two of the senior note indentures. Thus, we will be unable to incur unsecured non-bank debt or resume the payment of dividends on our preferred stock until we meet the debt incurrence test.

Canadian Operations Present the Risks Associated with Conducting Business Outside the U.S.

A portion of our business is conducted in Canada. You may review the amounts of revenue, operating income (loss) and identifiable assets attributable to our Canadian operations in Note 8 of the Notes to Consolidated Financial Statements in Item 8. Also, Note 11 of the Consolidated Financial Statements provides disclosures about our Canadian oil and gas producing activities. Our operations in Canada are subject to the risks associated with operating outside of the United States. These risks include the following:

- adverse local political or economic developments,
- exchange controls,

- currency fluctuations,
- royalty and tax increases,
- retroactive tax claims,
- negotiations of contracts with governmental entities, and
- import and export regulations.

In addition, in the event of a dispute, we may be required to litigate the dispute in Canadian courts since we may not be able to sue foreign persons in a United States court.

The Loss of Either the CEO or the COO Could Adversely Affect Operations.

Our operations are dependent upon our Chief Executive Officer, Aubrey K. McClendon, and our Chief Operating Officer, Tom L. Ward. The unexpected loss of the services of either of these executive officers could have a detrimental effect on our operations. We maintain $20 million key man life insurance policies on the life of each of Messrs. McClendon and Ward.

Transactions with Executive Officers May Create Conflicts of Interest.

Messrs. McClendon and Ward have the right to participate in certain wells we drill, subject to certain limitations outlined in their employment contracts. As a result of their participation, they routinely have significant accounts payable to Chesapeake for joint interest billings and other related advances. As of December 31, 1999, Messrs. McClendon and Ward had payables to Chesapeake of $2.5 million and $1.8 million, respectively, in connection with such participation. These amounts were reduced to $2.2 million and $1.2 million, respectively, as of March 22, 2000. The rights to participate in wells we drill could present a conflict of interest with respect to Messrs. McClendon and Ward.

The Ownership of a Significant Percentage of Stock by Insiders Could Influence the Outcome of Shareholder Votes.

At March 22, 2000, our Board of Directors and senior management beneficially owned an aggregate of 25,788,818 shares of common stock (including outstanding vested options), which represented approximately 24% of our outstanding shares. The beneficial ownership of Messrs. McClendon and Ward accounted for 21% of the outstanding common stock. As a result, Messrs. McClendon and Ward, together with other officers and directors of Chesapeake, are in a position to significantly influence matters requiring the vote or consent of our shareholders.

REGULATION

General

Numerous departments and agencies, 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. The regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, affects its profitability.

Exploration and Production

The Company's operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used or obtained in connection with operations. The Company's operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units and the density of wells which may be drilled 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 develop a prospect 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 the Company can produce from its wells and to limit the number of wells or the locations at which the Company can drill. The extent of any impact on the Company of such restrictions cannot be predicted.

Environmental and Occupational Regulation

General. The Company's activities are subject to existing federal, state and local laws and regulations governing environmental quality and pollution control. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations concerning the protection of the environment and human health will not have a material effect upon the operations, capital expenditures, earnings or the competitive position of the Company. The Company cannot predict what effect additional regulation or legislation, enforcement policies thereunder and claims for damages for injuries to property, employees, other persons and the environment resulting from the Company's operations could have on its activities.

Activities of the Company with respect to the exploration, development and production of oil and natural gas are subject to stringent environmental regulation by state and federal authorities including the United States Environmental Protection Agency ("EPA"). Such regulation has increased the cost of planning, designing, drilling, operating and in some instances, abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products and waste created by water and air pollution control procedures. Although the Company believes that compliance with environmental regulations will not have a material adverse effect on operations or earnings, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that significant costs and liabilities, including criminal penalties, will not be incurred. Moreover, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages for injuries to property or persons resulting from the Company's operations could result in substantial costs and liabilities.

Waste Disposal. The Company currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. State and federal laws applicable to oil and natural gas wastes and properties have gradually become more strict. Under such laws, the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The Company generates wastes, including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The EPA and various state agencies have limited the disposal options for certain hazardous and nonhazardous wastes and are considering the adoption of stricter disposal standards for nonhazardous wastes. Furthermore, certain wastes generated by the Company's 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.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner and operator of a site and persons that disposed of or arranged for the disposal of the hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from responsible classes of persons the costs of such action. In the course of its operations, the Company may have generated and may generate wastes that fall within CERCLA's definition of "hazardous substances". The Company may also be or have been an owner of sites on which "hazardous substances" have been released. The Company may be responsible under CERCLA for all or part of the costs to clean up sites at which such wastes have been released. To date, however, neither the Company nor, to its knowledge, its predecessors or successors have been named a potentially responsible party under CERCLA or similar state superfund laws affecting property owned or leased by the Company.

Air Emissions. The operations of the Company are subject to local, state and federal regulations for the control of emissions of air pollution. Legal and regulatory requirements in this area are increasing, and there can be no assurance that significant costs and liabilities will not be incurred in the future as a result of new regulatory developments. In particular, regulations promulgated under the Clean Air Act Amendments of 1990 may impose additional compliance requirements that could affect the Company's operations. However, it is impossible to predict accurately the effect, if any, of the Clean Air Act Amendments on the Company at this time. The Company may in the future be subject to civil or administrative enforcement actions for failure to comply strictly with air regulations or permits. These enforcement actions are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require the Company to forego construction or operation of certain air emission sources.

OSHA. The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and similar state statutes require the Company to organize information about hazardous materials used, released or produced in its operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. The Company is also subject to the requirements and reporting set forth in OSHA workplace standards. The Company provides safety training and personal protective equipment to its employees.

OPA and Clean Water Act. Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to prepare and implement spill prevention control plans, countermeasure plans and facilities response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") amends certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act ("CWA"), and other statutes as they pertain to the prevention of and response to oil spills into navigable waters. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The CWA provides penalties for any discharges of petroleum product in reportable quantities and imposes substantial liability for the costs of removing a spill. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground. Regulations are currently being developed under OPA and state laws concerning oil pollution prevention and other matters that may impose additional regulatory burdens on the Company. In addition, the CWA and analogous state laws require permits to be obtained to authorize discharges into surface waters or to construct facilities in wetland areas. With respect to certain of its operations, the Company is required to maintain such permits or meet general permit requirements. The EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, participate in a group permit or seek coverage under an EPA general permit. The Company believes that with respect to existing properties it has obtained, or is included under, such permits and with respect to future operations it will be able to obtain, or be included under, such permits, where necessary. Compliance with such permits is not expected to have a material effect on the Company.

NORM. Oil and gas exploration and production activities have been identified as generators of concentrations of low-level naturally-occurring radioactive materials ("NORM"). NORM regulations have recently been adopted in several states. The Company is unable to estimate the effect of these regulations, although based upon the

Company's preliminary analysis to date, the Company does not believe that its compliance with such regulations will have a material adverse effect on its operations or financial condition.

Safe Drinking Water Act. The Company's operations involve the disposal of produced saltwater and other nonhazardous oilfield wastes by reinjection into the subsurface. Under the Safe Drinking Water Act ("SDWA"), oil and gas operators, such as the Company, must obtain a permit for the construction and operation of underground Class II injection wells. To protect against contamination of drinking water, periodic mechanical integrity tests are often required to be performed by the well operator. The Company has obtained such permits for the Class II wells it operates. The Company also has disposed of wastes in facilities other than those owned by the Company which are commercial Class II injection wells.

Toxic Substances Control Act. The Toxic Substances Control Act ("TSCA") was enacted to control the adverse effects of newly manufactured and existing chemical substances. Under the TSCA, the EPA has issued specific rules and regulations governing the use, labeling, maintenance, removal from service and disposal of PCB items, such as transformers and capacitors used by oil and gas companies. The Company may own such PCB items but does not believe compliance with TSCA has or will have a material adverse effect on the Company's operations or financial condition.

TITLE TO PROPERTIES

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, the Company's title to oil and gas properties is challenged through legal proceedings. The Company is routinely involved in litigation involving title to certain of its oil and gas properties, some of which management believes could be adverse to the Company, 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 the Company 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. The Company's horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

The Company maintains a $50 million oil and gas lease operator policy that insures the Company against certain sudden and accidental risks associated with drilling, completing and operating its wells. There can be no assurance that this insurance will be adequate to cover any losses or exposure to liability. The Company also carries comprehensive general liability policies and a $75 million umbrella policy. The Company and its subsidiaries carry workers' compensation insurance in all states in which they operate and a $75 million employment practice liability policy. While the Company believes these policies are customary in the industry, they do not provide complete coverage against all operating risks.

EMPLOYEES

The Company had 424 full-time employees as of December 31, 1999. No employees are represented by organized labor unions. The Company considers its employee relations to be good.

FACILITIES

The Company owns an office building complex in Oklahoma City totaling approximately 86,500 square feet and nine acres of land that comprise its headquarters' offices. The Company also owns field offices in Lindsay and Waynoka, Oklahoma and Garden City, Kansas. The Company leases office space in Oklahoma City and Weatherford, Oklahoma; Fritch and Navasota, Texas; and in Dickinson, North Dakota. The Company also has leased office space in College Station, Texas; Wichita, Kansas; and Calgary, Alberta, Canada, which have been sub-leased.

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.

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

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

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

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

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

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

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

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

Horizontal Wells. Wells which are drilled at angles greater than 70 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.

Present Value. When used with respect to oil and gas reserves, present value 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

The Company focuses its natural gas exploration, development and acquisition efforts in three areas: (i) the Mid-Continent (consisting of Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle), (ii) the onshore Gulf Coast in Texas and Louisiana, and (iii) the Helmet area in northeastern British Columbia. In addition, Chesapeake has active oil exploration and development programs in southeast New Mexico; and in portions of North Dakota; Montana; and Saskatchewan, Canada which comprise the Williston Basin.

During the year ended December 31, 1999 ("1999"), the Company participated in 211 gross (119.7 net) wells, 135 of which were Company operated. A summary of the Company's drilling activities, capital expenditures and property sales by primary operating area is as follows ($ in thousands):

			CAPITAL EXPENDITURES - OIL AND GAS PROPERTIES					
	GROSS WELLS DRILLED	NET WELLS DRILLED	DRILLING	LEASEHOLD	SUB-TOTAL	ACQUISITIONS	SALE OF PROPERTIES	TOTAL
Mid-Continent	169	95.3	$ 55,670	$ 12,478	$ 68,148	$ 47,364	$ (36,702)	$ 78,810
Gulf Coast	10	3.7	22,049	8,288	30,337	629	(2,628)	28,338
Canada	12	7.5	27,380	1,982	29,362	4,100	(813)	32,649
All other areas........	20	13.2	24,106	1,315	25,421	--	(5,492)	19,929
Total	211	119.7	$129,205	$ 24,063	$ 153,268	$ 52,093	$ (45,635)	$159,726

The Company's proved reserves increased 11% to an estimated 1,206 Bcfe at December 31, 1999, compared to 1,091 Bcfe of estimated proved reserves at December 31, 1998 (see Note 11 of Notes to Consolidated Financial Statements in Item 8).

The Company's strategy for 2000 is to continue developing its natural gas assets by drilling, selective acquisitions and miscellaneous property divestitures. Accordingly, the Company has established a capital expenditure budget of $170-$190 million, including approximately $130-$140 million allocated to drilling, acreage acquisition, seismic and related capitalized internal costs, and $40-$50 million for acquisitions, debt repayment and general corporate purposes. This budget is subject to adjustment based on drilling results, oil and gas prices, and other factors.

PRIMARY OPERATING AREAS

Mid-Continent Region. The Company's Mid-Continent proved reserves of 758 Bcfe represented 63% of the Company's total proved reserves as of December 31, 1999 and this area produced 70 Bcfe, or 52% of the Company's 1999 production.

During 1999, the Company invested approximately $56 million to drill 169 gross (95.3 net) wells in the Mid-Continent. The Company anticipates spending approximately 55%-60% of its total budget for exploration and development activities in the Mid-Continent region during 2000. The Company anticipates the Mid-Continent will contribute approximately 79 Bcfe of production during 2000, or 56% of expected total production.

Gulf Coast. The Company's Gulf Coast proved reserves, consisting of the Austin Chalk Trend in Texas and Louisiana, the Wharton County area in Texas, and the Tuscaloosa Trend in Louisiana, represented 190 Bcfe, or 15% of the Company's total proved reserves as of December 31, 1999. During 1999, the Gulf Coast assets produced 45 Bcfe, or 34% of the Company's total production. The Company anticipates the Gulf Coast will contribute approximately 39 Bcfe of production during 2000, or 28% of expected total production.

During 1999, the Company invested approximately $22 million to drill 10 gross (3.7 net) wells in the Gulf Coast. For 2000, the Company anticipates spending approximately 15%-20% of its total budget for exploration and development activities in the Gulf Coast region.

Helmet Area. The Company's Canadian proved reserves of 178 Bcfe represented 15% of the Company's total proved reserves at December 31, 1999. During 1999, production from Canada was 12 Bcfe, or 9% of the

Company's total production. During 1999, the Company invested approximately $27 million to drill 12 gross (7.5 net) wells, install various pipelines and compressors, and to perform capital workovers in Canada. The Company anticipates spending approximately 10% of its total budget for exploration and development activities in Canada during 2000, and expects production of 12 Bcfe in Canada, or 9% of the Company's estimated total production for 2000.

OTHER OPERATING AREAS

In addition to the primary operating areas described above which are focused on natural gas properties, the Company maintains operations in the Permian Basin in New Mexico, and the Williston Basin in North Dakota; Montana; and Saskatchewan, Canada which are focused on developing oil properties. In 1999, these areas contributed 7 Bcfe, or 5% of the Company's total production. In 2000, production levels should increase to approximately 11 Bcfe as a result of the Company allocating approximately 10% of its total budget for exploration and development activities in these areas.

OIL AND GAS RESERVES

The tables below set forth information as of December 31, 1999 with respect to the Company's estimated proved reserves, the estimated future net revenue therefrom and the present value thereof at such date. Williamson Petroleum Consultants, Inc. evaluated 50% and Ryder Scott Company evaluated 16% of the Company's combined discounted future net revenues from the Company's estimated proved reserves at December 31, 1999. The remaining properties were evaluated internally by the Company's engineers. All estimates were prepared based upon a review of production histories and other geologic, economic, ownership and engineering data developed by the Company. 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 owned by the Company.

ESTIMATED PROVED RESERVES AS OF DECEMBER 31, 1999	OIL (MBBL)	GAS (MMCF)	TOTAL (MMCFE)
Proved developed	17,750	763,323	869,823
Proved undeveloped	7,045	293,503	335,772
Total proved	24,795	1,056,826	1,205,595

ESTIMATED FUTURE NET REVENUE AS OF DECEMBER 31, 1999(a)	PROVED DEVELOPED	PROVED UNDEVELOPED	TOTAL PROVED
	($ IN THOUSANDS)		
Estimated future net revenue	$1,470,297	$ 420,878	$1,891,175
Present value of future net revenue	$ 867,985	$ 221,511	$1,089,496

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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, 1999. 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 prices of $24.72 per barrel of oil and $2.25 per Mcf of gas.

The future net revenue attributable to the Company's estimated proved undeveloped reserves of $420.9 million at December 31, 1999, and the $221.5 million present value thereof, have been calculated assuming that the Company will expend approximately $212.5 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.

The Company's ownership interest used in calculating proved reserves and the estimated future net revenue therefrom was determined after giving effect to the assumed maximum participation by other parties to the Company's 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, 1999. There can be no assurance that all of the estimated proved reserves will be produced and sold at the assumed prices or that existing contracts will be honored or judicially enforced.

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 the control of the Company. The reserve data set forth herein 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 present value thereof 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 the Company's proved reserves.

See Item 1 and Note 11 of Notes to Consolidated Financial Statements included in Item 8 for a description of the Company's primary and other operating areas, production and other information regarding its oil and gas properties.

ITEM 3. LEGAL PROCEEDINGS

The Company is subject to ordinary routine litigation incidental to its business. In addition, the following matters are pending or were recently terminated:

Securities Litigation. On March 3, 2000, the U.S. District Court for the Western District of Oklahoma dismissed a consolidated class action complaint styled In re Chesapeake Energy Corporation Securities Litigation. The complaint, which consolidated twelve purported class action suits filed in August and September 1997, alleged violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 by the Company and certain of its officers and directors. The action was brought on behalf of purchasers of the Company's common stock and common stock options between January 25, 1996 and June 27, 1997. The complaint alleged that the defendants made material misrepresentations and failed to disclose material facts about the Company's exploration and drilling activities in the Louisiana Trend. The Court ruled that Chesapeake had disclosed the precise risks of its Louisiana Trend activities.

Bayard Drilling Technologies, Inc. On July 30, 1998, the plaintiffs in Yuan, et al. v. Bayard, et al. filed an amended class action complaint in the U.S. District Court for the Western District of Oklahoma alleging violations of Sections 11 and 12 of the Securities Act of 1933 and Section 408 of the Oklahoma Securities Act by the Company and others. The action, originally filed in February 1998, was brought purportedly on behalf of investors who purchased Bayard common stock in, or traceable to, Bayard's initial public offering in November 1997. The defendants include officers and directors of Bayard who signed the registration statement, selling shareholders (including the Company) and underwriters of the offering. Total proceeds of the offering were $254 million, of which the Company received net proceeds of $90 million.

Plaintiffs allege that the Company, which owned 30.1% of Bayard's outstanding common stock prior to the offering, was a controlling person of Bayard. Plaintiffs also allege that the Company had established an interlocking financial relationship with Bayard and was a customer of Bayard's drilling services under allegedly below-market terms. Plaintiffs assert that the Bayard prospectus contained material omissions and misstatements relating to (i) the Company's financial "problems" and their impact on Bayard's operating results, (ii) increased costs associated with Bayard's growth strategy, (iii) undisclosed pending related-party transactions between Bayard and third parties other than the Company, (iv) Bayard's planned use of offering proceeds and (v) Bayard's capital expenditures and liquidity. The alleged defective disclosures are claimed to have resulted in a decline in Bayard's share price following the public offering. Plaintiffs seek a determination that the suit is a proper class action and damages in an unspecified amount or rescission, together with interest and costs of litigation, including attorneys' fees.

On August 24, 1999, the District Court entered an order granting in part and denying in part defendants' motion to dismiss the action. The court dismissed plaintiffs' claims against the Company under Section 15 of the Securities Act of 1933 alleging that Chesapeake was a "controlling person" of Bayard. The Court denied that portion of defendants' motion seeking dismissal of plaintiffs' claims under Sections 11 and 12(a)(2) of the Securities Act of 1933 and Section 408 of the Oklahoma Securities Act. Of these, only the Section 11 claim and the Section 408 claim are asserted against the Company. The court has also entered an order setting September 15, 2000 as the cutoff for merits discovery, November 1, 2000 for the filing of any dispositive motions and February 1, 2001 as the trial date.

The Company believes that it has meritorious defenses to these claims and intends to defend this action vigorously. No estimate of loss or range of estimate of loss, if any, can be made at this time. Bayard, which was acquired by Nabors Industries, Inc. in April 1999, has been reimbursing the Company for its costs of defense as incurred.

Patent Litigation. In Union Pacific Resources Company v. Chesapeake, et al., filed in October 1996 in the U.S. District Court for the Northern District of Texas, Fort Worth Division, UPRC asserted that the Company had infringed UPRC's patent covering a "geosteering" method utilized in drilling horizontal wells. Following a trial to the court in June 1999, the court ruled on September 21, 1999 that the patent was invalid. Because the patent was declared invalid, the court held that the Company could not have infringed the patent, dismissed all of UPRC's claims with prejudice and assessed court costs against UPRC. The court concluded that the UPRC patent was invalid for failure to definitively describe the patented method in the patent claims and for failure to provide sufficient disclosure in the patent to enable one of ordinary skill in the art to practice the patented method. Appeals of the judgment by both the Company and UPRC are pending in the Federal Circuit Court of Appeals. Management is unable to predict the outcome of these appeals but believes the invalidity of the patent will be upheld on appeal. The Company has appealed the trial court's ruling denying the Company's request for attorneys' fees.

West Panhandle Field Cessation Cases. A subsidiary of the Company, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. are defendants in 13 lawsuits filed between June 1997 and January 1999 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which the Company acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees.

Plaintiffs claim the leases terminated upon the cessation of production for various periods primarily during the 1960s. In addition, plaintiffs seek to recover conversion damages, exemplary damages, attorneys' fees and interest. Defendants assert 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 13 cases have been tried; two are scheduled to be tried in May and June 2000; and trial dates have not been set for the other cases.

Following are the cases pending or tried in the District Court of Moore County, Texas, 69th Judicial District:

Lois Law, et al. v. NGPL, et al., No. 97-70, filed December 22, 1997, jury trial in June 1999, verdict for Company 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. CP and the other defendants have filed a motion to reconsider, a motion for new trial, and a notice of appeal.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-30, first filed December 17, 1997, refiled May 11, 1998, jury trial in June 1999, verdict for Company and co-defendants. The jury found plaintiffs' claims were barred by laches and adverse possession. On September 28, 1999, 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 as of June 28, 1999 of $545,000 from CP and $235,000 jointly and severally from the other two defendants. The court further awarded, jointly and severally from all defendants, $77,500 of attorneys' fees in the event of an appeal, $1,900 of sanctions, interest and court costs. CP and the other two defendants filed an appeal of the judgment in the Court of Appeals for the Seventh District of Texas in Amarillo on October 12, 1999, and they have each posted a supersedeas bond.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-36, first filed February 2, 1998, refiled May 20, 1998, jury trial in July 1999, verdict for plaintiffs. The jury found that the defendants were bad-faith trespassers and produced gas from the leases as a result of fraud. On September 28, 1999, the court entered final judgment for plaintiffs terminating the lease, quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs as of June 1, 1999 and awarding actual damages of $1.5 million, attorneys' fees of $97,500 in the event of an appeal, interest and court costs. CP's liability for this award is joint and several with the other two defendants. The court also awarded exemplary damages of $1.2 million against each of CP and the other two defendants. CP and the other two defendants filed an appeal of the judgment in the Court of Appeals for the Seventh District of Texas in Amarillo on October 12, 1999, and they have each posted a supersedeas bond.

A. C. Smith, et al. v. NGPL, et al., 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. A jury trial is scheduled in May 2000.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-35, first filed February 2, 1998, refiled May 20, 1998. On December 3, 1999, the Court entered a partial summary judgment finding the lease had terminated and that defendants' affirmative defenses all failed as a matter of law except with respect to the defense of revivor against certain of the plaintiffs. CP and the other defendants filed a motion to reconsider on December 22, 1999.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-49, first filed March 10, 1998, refiled May 29, 1998.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-50, first filed March 18, 1998, refiled May 29, 1998.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-51, first filed December 2, 1997, refiled May 29, 1998.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-48, first filed February 2, 1998, refiled May 29, 1998.

Joseph H. Pool, et al. v. NGPL, et al., No. 98-70, first filed March 23, 1998, refiled October 22, 1998.

The Pool cases listed above were first filed in the U.S. District Court, Northern District of Texas, Amarillo Division. Other related cases pending are the following:

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 Company and co-defendants. The jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches, and revivor. Plaintiffs have filed a motion for a new trial.

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. No trial date has been set.

Pace v. NGPL et al., U.S. District Court, Northern District of Texas, Amarillo Division, filed January 29, 1999. Defendants' motion for summary judgment pending. Trial date in June 2000.

Ralph W. Coon, et al. v. MC Panhandle, Inc., et al., U.S. District Court, Eastern District of Texas, Lufkin Division, No. 2:98-CV-63, filed March 27, 1998. All lease termination claims have been withdrawn. Only royalty calculation issues remain.

The Company has previously established an accrued liability that management believes will be sufficient to cover the estimated costs of litigation for each of these 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 other cases, the outcome of the remaining trials and the amount of damages that might ultimately be awarded could differ from management's estimates. Management believes, however, that the leases are valid, there is no basis for exemplary damages and that any findings of fraud or bad faith will be overturned on appeal. CP and the other defendants intend to vigorously defend 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

The 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 the common stock as reported by the New York Stock Exchange:

	COMMON STOCK	
	HIGH	LOW
Year ended December 31, 1998:		
First Quarter	7.75	5.50
Second Quarter	6.00	3.88
Third Quarter	4.06	1.13
Fourth Quarter	2.63	0.75
Year ended December 31, 1999:		
First Quarter	1.50	0.63
Second Quarter	2.94	1.31
Third Quarter	4.13	2.75
Fourth Quarter	3.88	2.13

At March 17, 2000 there were 1,105 holders of record of common stock and approximately 22,500 beneficial owners.

DIVIDENDS

The Company paid quarterly dividends of $0.02 per common share from July 1997 to July 1998. In September 1998 the Board of Directors determined that because of low oil and natural gas prices the payment of cash dividends on the common stock should be cancelled. The payment of future cash dividends, if any, will be reviewed periodically by the Board of Directors and will depend upon, among other things, the Company's financial condition, funds from operations, the level of its capital and development expenditures, its future business prospects and any contractual restrictions.

Two of the indentures governing the Company's outstanding senior notes contain restrictions on the Company's ability to declare and pay dividends. Under these indentures, the Company may not pay any cash dividends on its common or preferred stock if (i) a default or an event of default has occurred and is continuing at the time of or immediately after giving effect to the dividend payment, (ii) the Company would not be able to incur at least $1 of additional indebtedness under the terms of the indentures, or (iii) immediately after giving effect to the dividend payment, the aggregate of all dividends and other restricted payments declared or made after the respective issue dates of the notes exceeds the sum of specified income, proceeds from the issuance of stock and debt by the Company and other amounts from the quarter in which the respective note issuances occurred to the quarter immediately preceding the date of the dividend payment. From December 31, 1998 through December 31, 1999, the Company did not meet the debt incurrence tests under these indentures and was not able to pay dividends on its preferred stock.

Subsequent to December 31, 1999, the Company entered into a number of unsolicited transactions whereby the Company issued approximately 8.8 million shares of the Company's common shares in exchange for 625,000 shares of the Company's preferred stock. This reduced the liquidation amount of preferred stock outstanding by $31.3 million to $198.7 million, and reduced the amount of preferred dividends in arrears by $2.9 million to $19.3 million as of February 29, 2000.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data of the Company for each of the two fiscal years ended June 30, 1997, the six-month Transition Period ended December 31, 1997, the six months ended December 31, 1996 and the twelve months ended December 31, 1999, 1998 and 1997. The data are derived from the audited consolidated financial statements of the Company, although the periods for the year ended December 31, 1997 and the six months ended December 31, 1996 have not been audited. Acquisitions made by the Company during the first and second quarters of 1998 materially affect the comparability of the selected financial data for 1997 and 1998. 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 the Consolidated Financial Statements, including the notes thereto, appearing in Items 7 and 8 of this report.

	YEARS ENDED DECEMBER 31,			SIX MONTHS ENDED DECEMBER 31,	
	1999	1998	1997	1997	1996
			(unaudited)		(unaudited)
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)				
STATEMENT OF OPERATIONS DATA:					
Revenues:					
Oil and gas sales	$ 280,445	$ 256,887	$ 198,410	$ 95,657	$ 90,167
Oil and gas marketing sales	74,501	121,059	104,394	58,241	30,019
Oil and gas service operations	--	--	--	--	--
Total revenues	354,946	377,946	302,804	153,898	120,186
Operating costs:					
Production expenses	46,298	51,202	14,737	7,560	4,268
Production taxes	13,264	8,295	4,590	2,534	1,606
General and administrative	13,477	19,918	10,910	5,847	3,739
Oil and gas marketing expenses	71,533	119,008	103,819	58,227	29,548
Oil and gas service operations	--	--	--	--	--
Oil and gas depreciation, depletion and amortization	95,044	146,644	127,429	60,408	36,243
Depreciation and amortization of other assets	7,810	8,076	4,360	2,414	1,836
Impairment of oil and gas properties	--	826,000	346,000	110,000	--
Impairment of other assets	--	55,000	--	--	--
Total operating costs	247,426	1,234,143	611,845	246,990	77,240
Income (loss) from operations	107,520	(856,197)	(309,041)	(93,092)	42,946
Other income (expense):					
Interest and other income	8,562	3,926	87,673	78,966	2,516
Interest expense	(81,052)	(68,249)	(29,782)	(17,448)	(6,216)
	(72,490)	(64,323)	57,891	61,518	(3,700)
Income (loss) before income taxes and extraordinary item	35,030	(920,520)	(251,150)	(31,574)	39,246
Provision (benefit) for income taxes	1,764	--	(17,898)	--	14,325
Income (loss) before extraordinary item	33,266	(920,520)	(233,252)	(31,574)	24,921
Extraordinary item:					
Loss on early extinguishment of debt, net of applicable income taxes	--	(13,334)	(177)	--	(6,443)
Net income (loss)	33,266	(933,854)	(233,429)	(31,574)	18,478
Preferred stock dividends	(16,711)	(12,077)	--	--	--
Net income (loss) available to common shareholders	$ 16,555	$ (945,931)	$ (233,429)	$ (31,574)	$ 18,478
Earnings (loss) per common share - basic:					
Income (loss) before extraordinary item	$ 0.17	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.40
Extraordinary item	--	(0.14)	--	--	(0.10)
Net income (loss)	$ 0.17	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.30
Earnings (loss) per common share - assuming dilution:					
Income (loss) before extraordinary item	$ 0.16	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.38
Extraordinary item	--	(0.14)	--	--	(0.10)
Net income (loss)	$ 0.16	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.28
Cash dividends declared per common share	$ --	$ 0.04	$ 0.06	$ 0.04	$ --
CASH FLOW DATA:					
Cash provided by operating activities before changes in working capital	$ 138,727	$ 117,500	$ 152,196	$ 67,872	$ 76,816
Cash provided by operating activities	145,022	94,639	181,345	139,157	41,901
Cash used in investing activities	159,773	548,050	476,209	136,504	184,149
Cash provided by (used in) financing activities	18,967	363,797	277,985	(2,810)	231,349
Effect of exchange rate changes on cash	4,922	(4,726)	--	--	--
BALANCE SHEET DATA (at end of period):					
Total assets	$ 850,533	$ 812,615	$ 952,784	$ 952,784	$ 860,597
Long-term debt, net of current maturities	964,097	919,076	508,992	508,992	220,149
Stockholders' equity (deficit)	(217,544)	(248,568)	280,206	280,206	484,062

	YEARS ENDED JUNE 30,	
	1997	1996

($ IN THOUSANDS, EXCEPT PER SHARE DATA)

STATEMENT OF OPERATIONS DATA:		
Revenues:		
Oil and gas sales	$ 192,920	$ 110,849
Oil and gas marketing sales	76,172	28,428
Oil and gas service operations	--	6,314
Total revenues	269,092	145,591
Operating costs:		
Production expenses	11,445	6,340
Production taxes	3,662	1,963
General and administrative	8,802	4,828
Oil and gas marketing expenses	75,140	27,452
Oil and gas service operations	--	4,895
Oil and gas depreciation, depletion and amortization	103,264	50,899
Depreciation and amortization of other assets	3,782	3,157
Impairment of oil and gas properties	236,000	--
Impairment of other assets	--	--
Total operating costs	442,095	99,534
Income (loss) from operations	(173,003)	46,057
Other income (expense):		
Interest and other income	11,223	3,831
Interest expense	(18,550)	(13,679)
	(7,327)	(9,848)
Income (loss) before income taxes and extraordinary item	(180,330)	36,209
Provision (benefit) for income taxes	(3,573)	12,854
Income (loss) before extraordinary item	(176,757)	23,355
Extraordinary item:		
Loss on early extinguishment of debt, net of applicable income taxes	(6,620)	--
Net income (loss)	(183,377)	23,355
Preferred stock dividends	--	--
Net income (loss) available to common shareholders	$ (183,377)	$ 23,355
Earnings (loss) per common share - basic:		
Income (loss) before extraordinary item	$ (2.69)	$ 0.43
Extraordinary item	(0.10)	--
Net income (loss)	$ (2.79)	$ 0.43
Earnings (loss) per common share - assuming dilution:		
Income (loss) before extraordinary item	$ (2.69)	$ 0.40
Extraordinary item	(0.10)	--
Net income (loss)	$ (2.79)	$ 0.40
Cash dividends declared per common share	$ 0.02	$ --
CASH FLOW DATA:		
Cash provided by operating activities before changes in working capital	$ 161,140	$ 88,431
Cash provided by operating activities	84,089	120,972
Cash used in investing activities	523,854	344,389
Cash provided by (used in) financing activities	512,144	219,520
Effect of exchange rate changes on cash	--	--
BALANCE SHEET DATA (at end of period):		
Total assets	$ 949,068	$ 572,335
Long-term debt, net of current maturities	508,950	268,431
Stockholders' equity (deficit)	286,889	177,767

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

The following table sets forth certain operating data of the Company for the periods presented:

	YEARS ENDED DECEMBER 31,		
	1999	1998	1997
NET PRODUCTION DATA:			
Oil (MBbl)	4,147	5,976	3,511
Gas (MMcf)	108,610	94,421	59,236
Gas equivalent (MMcfe)	133,492	130,277	80,302
OIL AND GAS SALES ($ IN 000'S):			
Oil	$ 66,413	$ 75,877	$ 68,079
Gas	214,032	181,010	130,331
Total oil and gas sales	$ 280,445	$ 256,887	$ 198,410
AVERAGE SALES PRICE:			
Oil ($ per Bbl)	$ 16.01	$ 12.70	$ 19.39
Gas ($ per Mcf)	$ 1.97	$ 1.92	$ 2.20
Gas equivalent ($ per Mcfe)	$ 2.10	$ 1.97	$ 2.47
OIL AND GAS COSTS ($ PER MCFE):			
Production expenses and taxes	$ .45	$ .45	$ .24
General and administrative	$ .10	$ .15	$ .14
Depreciation, depletion and amortization	$ .71	$ 1.13	$ 1.59
NET WELLS DRILLED:			
Horizontal wells	11	20	69
Vertical wells	109	116	32
NET WELLS AT END OF PERIOD	2,242	2,405	401

RESULTS OF OPERATIONS

Years Ended December 31, 1999, 1998 and 1997

General. In 1999, the Company had net income of $33.3 million, or $0.16 per diluted common share, on total revenues of $354.9 million. This compares to a net loss of $933.9 million, or a loss of $9.97 per diluted common share, on total revenues of $377.9 million during the year ended December 31, 1998 ("1998"), and a net loss of $233.4 million, or a loss of $3.30 per diluted common share, on total revenues of $302.8 million during the year ended December 31, 1997 ("1997"). The loss in 1998 was caused primarily by an $826.0 million oil and gas property writedown recorded under the full-cost method of accounting and a $55.0 million writedown of other assets. The loss in 1997 was caused primarily by a $346 million oil and gas property writedown. See "Impairment of Oil and Gas Properties" and "Impairment of Other Assets".

Oil and Gas Sales. During 1999, oil and gas sales increased to $280.4 million versus $256.9 million in 1998 and $198.4 million in 1997. In 1999, the Company produced 133.5 Bcfe at a weighted average price of $2.10 per Mcfe, compared to 130.3 Bcfe produced in 1998 at a weighted average price of $1.97 per Mcfe, and 80.3 Bcfe produced in 1997 at a weighted average price of $2.47 per Mcfe.

The following table shows the Company's production by region for 1999, 1998 and 1997:

	FOR THE YEARS ENDED DECEMBER 31,					
	1999		1998		1997	
	MMCFE	PERCENT	MMCFE	PERCENT	MMCFE	PERCENT
Mid-Continent	69,946	52%	61,930	48%	17,685	22%
Gulf Coast	44,822	34	52,793	40	60,662	76
Canada	11,737	9	7,746	6	--	--
All other areas	6,987	5	7,808	6	1,955	2
Total production	133,492	100%	130,277	100%	80,302	100%

Natural gas production represented approximately 81% of the Company's total production volume on an equivalent basis in 1999, compared to 72% in 1998 and 74% in 1997.

For 1999, the Company realized an average price per barrel of oil of $16.01, compared to $12.70 in 1998 and $19.39 in 1997. Gas price realizations fluctuated from an average of $1.92 per Mcf in 1998 and $2.20 in 1997 to $1.97 per Mcf in 1999. The Company's hedging activities resulted in a decrease in oil and gas revenues of $1.7 million in 1999, an increase in oil and gas revenues of $11.3 million in 1998, and a decrease in oil and gas revenues of $4.6 million in 1997.

Oil and Gas Marketing Sales. The Company realized $74.5 million in oil and gas marketing sales for third parties in 1999, with corresponding oil and gas marketing expenses of $71.5 million, for a net margin of $3.0 million. This compares to sales of $121.1 million and $104.4 million, expenses of $119.0 million and $103.8 million, and a margin of $2.1 million and $0.6 million in 1998 and 1997, respectively.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and ad valorem taxes, were $59.6 million in 1999, compared to $59.5 million and $19.3 million in 1998 and 1997, respectively. On a unit of production basis, production expenses and taxes were $0.45 per Mcfe in 1999 and 1998, and $0.24 per Mcfe in 1997. The Company expects that lease operating expenses per Mcfe will generally remain at current levels throughout 2000, although production taxes will increase as a result of increased oil and gas prices.

Impairment of Oil and Gas Properties. The Company utilizes the full-cost method to account for its investment in oil and gas properties. Under this method, all costs of acquisition, exploration and development of oil and gas reserves (including such costs as leasehold acquisition costs, geological and geophysical expenditures, certain capitalized internal costs, dry hole costs and tangible and intangible development costs) are capitalized as incurred. These oil and gas property costs, along with the estimated future capital expenditures to develop proved undeveloped reserves, are depleted and charged to operations using the unit-of-production method based on the ratio of current production to proved oil and gas reserves as estimated by the Company's independent engineering consultants and Company engineers. Costs directly associated with the acquisition and evaluation of unproved properties are excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the property or whether impairment has occurred. The excess of capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes, over the discounted future net revenues of proved oil and gas properties is charged to operations.

The Company incurred an impairment of oil and gas properties charge of $826 million in 1998. No such charge was incurred in 1999. The 1998 writedown was caused by a combination of several factors, including the acquisitions completed by the Company during 1998, which were accounted for using the purchase method, and the significant decreases in oil and gas prices throughout 1998. Oil and gas prices used to value the Company's proved reserves decreased from $17.62 per Bbl of oil and $2.29 per Mcf of gas at December 31, 1997, to $10.48 per Bbl of oil and $1.68 per Mcf of gas at December 31, 1998. Higher drilling and completion costs and the evaluation of certain leasehold, seismic and other exploration-related costs that were previously unevaluated were the remaining factors which contributed to the writedown in 1998.

The Company incurred an impairment of oil and gas properties charge of $346 million during 1997. The writedown in 1997 was caused by several factors, including declining oil and gas prices during the year, escalating drilling and completion costs, and poor drilling results primarily in Louisiana.

Impairment of Other Assets. The Company incurred a $55 million impairment charge during 1998. Of this amount, $30 million related to the Company's investment in preferred stock of Gothic Energy Corporation, and the remainder was related to certain of the Company's gas processing and transportation assets located in Louisiana. No such charge was recorded in 1999 or 1997.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization ("DD&A") of oil and gas properties was $95.0 million, $146.6 million and $127.4 million during 1999, 1998 and 1997, 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 $0.71 ($0.73 in U.S. and $0.52 in Canada), $1.13

($1.17 in U.S. and $0.43 in Canada) and $1.59 (U.S. only) in 1999, 1998 and 1997, respectively. The Company expects the 2000 DD&A rate to be between $0.75 and $0.80 per Mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization ("D&A") of other assets was $7.8 million in 1999, compared to $8.1 million in 1998 and $4.4 million in 1997. The increase in 1998 compared to 1997 was caused by increased investments in depreciable buildings and equipment and increased amortization of debt issuance costs as a result of the issuance of senior notes in April 1998.

General and Administrative. General and administrative ("G&A") expenses, which are net of capitalized internal payroll and non-payroll expenses (see Note 11 of Notes to Consolidated Financial Statements), were $13.5 million in 1999, $19.9 million in 1998 and $10.9 million in 1997. The decrease in 1999 compared to 1998 was due primarily to various actions taken to lower corporate overhead, including staff reductions and office closings which occurred in late 1998 and early 1999. The increase in 1998 compared to 1997 is due primarily to increased personnel expenses required by the Company's growth and industry wage inflation. The Company capitalized $2.7 million, $5.3 million and $5.3 million of internal costs in 1999, 1998 and 1997, respectively, directly related to the Company's oil and gas exploration and development efforts. The Company anticipates that G&A costs for 2000 per Mcfe will remain at approximately the same level as 1999.

Interest and Other Income. Interest and other income for 1999 was $8.6 million compared to $3.9 million in 1998, and $87.7 million in 1997. The increase from 1998 to 1999 was due primarily to gains on sales of various non-core assets during 1999. During 1997, the Company realized a gain on the sale of its Bayard common stock of $73.8 million, the most significant component of interest and other income.

Interest Expense. Interest expense increased to $81.1 million in 1999, compared to $68.2 million in 1998 and $29.8 million in 1997. The increase in 1999 is due primarily to a full year of interest on the Company's $500 million senior notes. The increase in 1998 compared to 1997 was due primarily to the issuance of $500 million of senior notes in April 1998. In addition to the interest expense reported, the Company capitalized $3.5 million of interest during 1999, compared to $6.5 million capitalized in 1998, and $10.4 million capitalized in 1997. The Company anticipates that capitalized interest for 2000 will be between $3 million and $4 million.

Provision (Benefit) for Income Taxes. The Company recorded income taxes of $1.8 million in 1999 compared to $0 in 1998 and an income tax benefit of $17.9 million in 1997. The income tax expense recorded in 1999 is related entirely to the Company's Canadian operations.

At December 31, 1999, the Company had a U.S. net operating loss carryforward of approximately $613 million for regular federal income taxes which will expire in future years beginning in 2007. Management believes that it cannot be demonstrated at this time that it is more likely than not that the deferred income tax assets, comprised primarily of the net operating loss carryforwards generated for U.S. purposes, will be realizable in future years, and therefore a valuation allowance of $442 million has been recorded. The Company does not expect to record any net income tax expense related to its U.S. operations in 2000 based on information available at this time.

LIQUIDITY AND CAPITAL RESOURCES

Years Ended December 31, 1999, 1998 and 1997

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in working capital) was $145.0 million in 1999, compared to $94.6 million in 1998 and $181.3 million in 1997. The increase of $50.4 million from 1998 to 1999 was due primarily to increased oil and gas revenues. The decrease of $86.7 million from 1997 to 1998 was due primarily to reduced operating income resulting from significant decreases in average oil and gas prices between periods, as well as significant increases in G&A expenses and interest expense.

Cash Flows from Investing Activities. Cash used in investing activities decreased to $159.8 million in 1999, compared to $548.1 million in 1998 and $476.2 million in 1997. During 1999, the Company invested $153.3 million for exploration and development drilling, $49.9 million for the acquisition of oil and gas properties, and received $45.6 million related to divestitures of oil and gas properties. During 1998, $279.9 million was used to acquire certain oil and gas properties and companies with oil and gas reserves. However, the increase in cash used to acquire oil and gas properties was partially offset by reduced expenditures during 1998 for exploratory and developmental drilling. During 1998 and 1997, the Company invested $259.7 million and $471.0 million, respectively, for exploratory and developmental drilling. Also during 1998, the Company sold its 19.9% stake in Pan East Petroleum Corp. to Poco Petroleums, Ltd. for approximately $21.2 million. During 1997 the Company received net proceeds from the sale of its investment in Bayard common stock of approximately $90.4 million.

Cash Flows from Financing Activities. Cash provided by financing activities decreased to $19.0 million in 1999, compared to $363.8 million in 1998, and $278.0 million in 1997. During 1999, the Company made additional borrowings under its commercial bank credit facility of $116.5 million, and had payments under this facility of $98.0 million. During 1998, the Company retired $85 million of debt assumed at the completion of the DLB Oil & Gas, Inc. acquisition, $120 million of debt assumed at the completion of the Hugoton Energy Corporation acquisition, $90 million of senior notes, and $170 million of borrowings made under its commercial bank credit facilities. Also during 1998, the Company issued $500 million in senior notes and $230 million in preferred stock. During 1997, the Company issued $300 million of senior notes.

Financial Flexibility and Liquidity

The Company had working capital of $9.4 million at December 31, 1999 and a cash balance of $38.7 million. The Company has a $50 million revolving bank credit facility which matures in January 2001, with an initial committed borrowing base of $50 million. As of December 31, 1999, the Company had borrowed $43.5 million under this facility. Borrowings under the facility are secured by certain producing oil and gas properties and bear interest at a variable rate, which was 9.75% per annum as of December 31, 1999.

At December 31, 1999, the Company's senior notes represented $919.2 million of its $964.1 million of long-term debt. Debt ratings for the senior notes are B3 by Moody's Investors Service and B by Standard & Poor's Corporation as of March 22, 2000. There are no scheduled principal payments required on any of the senior notes until March 2004, when $150 million is due.

The senior note indentures restrict the ability of the Company and its restricted subsidiaries to incur additional indebtedness. As of December 31, 1999, the Company estimates that secured commercial bank indebtedness of $147 million could have been incurred within these restrictions. The indenture restrictions do not apply to borrowings incurred by CEMI, an unrestricted subsidiary.

The senior note indentures also limit the Company's ability to make restricted payments (as defined), including the payment of preferred stock dividends, unless certain tests are met. From December 31, 1998 through December 31, 1999, the Company was unable to meet the requirements to incur additional unsecured indebtedness, and consequently was not able to pay cash dividends on its 7% cumulative convertible preferred stock. The Company had accumulated dividends in arrears of $19.3 million related to its preferred stock as of February 29, 2000. Subsequent payments will be subject to the same restrictions and are dependent upon variables that are beyond the Company's ability to predict. This restriction does not affect the Company's ability to borrow under or expand its secured commercial bank facility. If the Company fails to pay dividends for six quarterly periods, the holders of preferred stock will be entitled to elect two new directors to the Board. Based on current projections of cash flow and fixed charges, the Company does not expect to be able to pay a dividend on the preferred stock on May 1, 2000, which would be the sixth consecutive dividend payment date on which dividends have not been paid.

In January and February 2000, the Company engaged in five separate transactions with two institutional investors in which the Company exchanged a total of 8.8 million shares of common stock (both newly issued and treasury shares) for 625,000 shares of its issued and outstanding preferred stock with a liquidation value of $31.3

million plus dividends in arrears of $2.9 million. All preferred shares acquired in these transactions were cancelled and retired and will have the status of authorized but unissued shares of undesignated preferred stock.

The Company believes it has adequate resources, including cash on hand, budgeted cash flow from operations and proceeds from miscellaneous asset sales, to fund its capital expenditure budget for exploration and development activities during 2000, which are currently estimated to be approximately $130-$140 million. However, low oil and gas prices or unfavorable drilling results could cause the Company to reduce its drilling program, which is largely discretionary.

RECENTLY ISSUED ACCOUNTING STANDARDS

On June 15, 1998, the Financial Accounting Standards Board issued FAS No. 133, Accounting for Derivative Instruments and Hedging Activities ("FAS 133"). FAS 133 establishes a new model for accounting for derivatives and hedging activities and supersedes and amends a number of existing standards. FAS 133 (as amended by FAS 137) is effective for all fiscal quarters of fiscal years beginning after June 15, 2000.

FAS 133 standardizes the accounting for derivative instruments by requiring that all derivatives be recognized as assets and liabilities and measured at fair value. The accounting for changes in the fair value of derivatives (gains and losses) depends on (i) whether the derivative is designated and qualifies as a hedge, and (ii) the type of hedging relationship that exists. Changes in the fair value of derivatives that are not designated as hedges or that do not meet the hedge accounting criteria in FAS 133 are required to be reported in earnings. In addition, all hedging relationships must be designated, reassessed and documented pursuant to the provisions of FAS 133. The Company has not yet determined the impact that adoption of FAS 133 will have on the financial statements. However, the Company believes that all of its derivative instruments will be designated as hedges in accordance with the relevant accounting criteria, and therefore the impact of the adoption of FAS 133 is not expected to have a material effect on the Company's financial statements.

FORWARD-LOOKING STATEMENTS

This Form 10-K 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. All statements other than statements of historical facts included in this Form 10-K, including, without limitation, statements regarding oil and gas reserve estimates, planned capital expenditures, expected oil and gas production, the Company's financial position, business strategy and other plans and objectives for future operations, expected future expenses, and realization of deferred tax assets, are forward-looking statements. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Factors that could cause actual results to differ materially from those expected by the Company, including, without limitation, factors discussed under Risk Factors in Item 1 of this Form 10-K, are substantial indebtedness, impairment of asset value, need to replace reserves, substantial capital requirements, ability to supplement capital resources with asset sales, fluctuations in the prices of oil and gas, uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures, competition, operating risks, restrictions imposed by lenders, liquidity and capital requirements, the effects of governmental and environmental regulation, pending litigation, and adverse changes in the market for the Company's oil and gas production. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. The Company undertakes no obligation to release publicly the result of any revisions to these forward-looking statements that may be made to reflect events or circumstances after the date hereof, including, without limitation, changes in the Company's business strategy or planned capital expenditures, or to reflect the occurrence of unanticipated events.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

COMMODITY PRICE RISK

The Company's results of operations are highly dependent upon the prices received for oil and natural gas production.

HEDGING ACTIVITIES

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include:

(i) swap arrangements that establish an index-related price above which the Company pays the counterparty and below which the Company is paid by the counterparty,

(ii) the purchase of index-related puts that provide for a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor,

(iii) the sale of index-related calls that provide for a "ceiling" price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling, and

(iv) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points.

Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to the Company's oil and gas production. The Company only enters into commodity hedging transactions related to the Company's oil and gas production volumes or CEMI's physical purchase or sale commitments. Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the months of related production.

As of December 31, 1999, the Company had the following open natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1999:

MONTHS	VOLUME (MMBTU)	NYMEX-INDEX STRIKE PRICE (PER MMBTU)
April 2000	600,000	$ 2.50
May 2000	620,000	2.50
June 2000	600,000	2.50
July 2000	620,000	2.50
August 2000	620,000	2.50
September 2000	600,000	2.50
October 2000	620,000	2.50

If the swap arrangements listed above had been settled on December 31, 1999, the Company would have incurred a gain of $0.5 million.

As of December 31, 1999, the Company had no open oil swap arrangements.

The Company has also closed transactions designed to hedge a portion of the Company's domestic oil and natural gas production. The net unrecognized losses resulting from these transactions, $3.9 million as of December 31, 1999, will be recognized as price adjustments in the months of related production. These hedging gains and losses are set forth below ($ in thousands):

	HEDGING GAINS (LOSSES)		
MONTH	GAS	OIL	TOTAL
January 2000	$ --	$ (995)	$ (995)
February 2000	--	(1,061)	(1,061)
March 2000	689	(851)	(162)
April 2000	71	(647)	(576)
May 2000	73	(668)	(595)
June 2000	71	(647)	(576)
July 2000	73	(231)	(158)
August 2000	73	--	73
September 2000	71	--	71
October 2000	73	--	73
	$ 1,194	$ (5,100)	$ (3,906)

Subsequent to December 31, 1999, the Company entered into the following natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1999:

MONTHS	VOLUME (MMBTU)	NYMEX - INDEX STRIKE PRICE (PER MMBTU)
April 2000	8,900,000	$2.593
May 2000	3,410,000	2.737
June 2000	3,300,000	2.737
July 2000	3,410,000	2.741
August 2000	3,410,000	2.741
September 2000	2,100,000	2.696
October 2000	2,170,000	2.696

Subsequent to December 31, 1999, the Company entered into the following crude oil swap arrangements designed to hedge a portion of the Company's domestic crude oil production for periods after December 1999:

MONTHS	MONTHLY VOLUME (BBLS)	NYMEX-INDEX STRIKE PRICE (PER BBL)
March 2000	183,000	$27.512
April 2000	89,000	27.251

In addition to commodity hedging transactions related to the Company's oil and gas production, CEMI periodically enters into various hedging transactions designed to hedge against physical purchase and sale commitments made by CEMI. Gains or losses on these transactions are recorded as adjustments to oil and gas marketing sales in the consolidated statements of operations and are not considered by management to be material.

INTEREST RATE RISK

The Company also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, the Company believes it can benefit from stable or falling interest rates and reduce its current interest expense. During 1999, the Company's interest rate swap resulted in a $2.0 million reduction of interest expense. The terms of the swap agreement are as follows:

Months	Notional Amount	Fixed Rate	Floating Rate
May 1998 - April 2001	$230,000,000	7%	Average of three-month Swiss Franc LIBOR, Deutsche Mark and Australian Dollar plus 300 basis points
May 2001 - April 2008	$230,000,000	7%	U.S. three-month LIBOR plus 300 basis points

If the floating rate is less than the fixed rate, the counterparty will pay the Company accordingly. If the floating rate exceeds the fixed rate, the Company will pay the counterparty.

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

	DECEMBER 31, 1999							
	YEARS OF MATURITY							
	2000	2001	2002	2003	2004	THEREAFTER	TOTAL	FAIR VALUE
LIABILITIES:				($ IN MILLIONS)				
Long-term debt, including current portion - fixed rate....	$ 0.8	$ 0.8	$ 0.6	$ --	$ 150.0	$ 770.0	$ 922.2	$ 838.7
Average interest rate......	9.1%	9.1%	9.1%	--	7.9%	9.3%	9.1%	--
Long-term debt - variable rate	$ --	$ 43.5	$ --	$ --	$ --	$ --	$ 43.5	$ 43.5
Average interest rate......	--	9.75%	--	--	--	--	9.75%	--

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders
of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at December 31, 1999 and 1998, and the results of their operations and their cash flows for the years ended December 31, 1999 and 1998, the six months ended December 31, 1997, and the year ended June 30, 1997, in conformity with accounting principles generally accepted in the United States. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with auditing standards generally accepted in the United States, 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 the opinion expressed above.

PRICEWATERHOUSECOOPERS LLP
Oklahoma City, Oklahoma
March 24, 2000

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

	DECEMBER 31, 1999	DECEMBER 31, 1998
	($ IN THOUSANDS)	
CURRENT ASSETS:		
Cash and cash equivalents	$ 38,658	$ 29,520
Restricted cash	192	5,754
Accounts receivable:		
Oil and gas sales	17,045	13,835
Oil and gas marketing sales	18,199	19,636
Joint interest and other, net of allowances of $ 3,218,000 and $3,209,000, respectively	11,247	27,373
Related parties	4,574	15,455
Inventory	4,582	5,325
Other	3,049	1,101
Total Current Assets	97,546	117,999
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	2,315,348	2,142,943
Unevaluated properties	40,008	52,687
Less: accumulated depreciation, depletion and amortization	(1,670,542)	(1,574,282)
	684,814	621,348
Other property and equipment	67,712	79,718
Less: accumulated depreciation and amortization	(33,429)	(37,075)
Total Property and Equipment	719,097	663,991
OTHER ASSETS	33,890	30,625
TOTAL ASSETS	$ 850,533	$ 812,615
CURRENT LIABILITIES:		
Notes payable and current maturities of long-term debt	$ 763	$ 25,000
Accounts payable	24,822	36,854
Accrued liabilities and other	34,713	46,572
Revenues and royalties due others	27,888	22,858
Total Current Liabilities	88,186	131,284
LONG-TERM DEBT, NET	964,097	919,076
REVENUES AND ROYALTIES DUE OTHERS	9,310	10,823
DEFERRED INCOME TAXES	6,484	--
CONTINGENCIES AND COMMITMENTS (NOTE 4)		
STOCKHOLDERS' EQUITY (DEFICIT):		
Preferred Stock, $.01 par value, 10,000,000 shares authorized; 4,596,400 and 4,600,000 shares of 7% cumulative convertible stock issued and outstanding at December 31, 1999 and 1998, respectively, entitled in liquidation to $229.8 million and 230.0 million, respectively	229,820	230,000
Common Stock, par value of $.01, 250,000,000 shares authorized; 105,858,580 and 105,213,750 shares issued at December 31, 1999 and 1998, respectively	1,059	1,052
Paid-in capital	682,905	682,263
Accumulated earnings (deficit)	(1,093,929)	(1,127,195)
Accumulated other comprehensive income (loss)	196	(4,726)
Less: treasury stock, at cost; 10,856,185 and 8,503,300 common shares at December 31, 1999 and 1998, respectively	(37,595)	(29,962)
Total Stockholders' Equity (Deficit)	(217,544)	(248,568)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 850,533	$ 812,615

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	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)			
REVENUES:				
Oil and gas sales	$ 280,445	$ 256,887	$ 95,657	$ 192,920
Oil and gas marketing sales	74,501	121,059	58,241	76,172
Total Revenues	354,946	377,946	153,898	269,092
OPERATING COSTS:				
Production expenses	46,298	51,202	7,560	11,445
Production taxes	13,264	8,295	2,534	3,662
General and administrative	13,477	19,918	5,847	8,802
Oil and gas marketing expenses	71,533	119,008	58,227	75,140
Oil and gas depreciation, depletion and amortization	95,044	146,644	60,408	103,264
Depreciation and amortization of other assets	7,810	8,076	2,414	3,782
Impairment of oil and gas properties	--	826,000	110,000	236,000
Impairment of other assets	--	55,000	--	--
Total Operating Costs	247,426	1,234,143	246,990	442,095
INCOME (LOSS) FROM OPERATIONS	107,520	(856,197)	(93,092)	(173,003)
OTHER INCOME (EXPENSE):				
Interest and other income	8,562	3,926	78,966	11,223
Interest expense	(81,052)	(68,249)	(17,448)	(18,550)
	(72,490)	(64,323)	61,518	(7,327)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	35,030	(920,520)	(31,574)	(180,330)
PROVISION (BENEFIT) FOR INCOME TAXES	1,764	--	--	(3,573)
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	33,266	(920,520)	(31,574)	(176,757)
EXTRAORDINARY ITEM:				
Loss on early extinguishment of debt, net of applicable income tax of $0 and $3,804,000, respectively	--	(13,334)	--	(6,620)
NET INCOME (LOSS)	33,266	(933,854)	(31,574)	(183,377)
PREFERRED STOCK DIVIDENDS	(16,711)	(12,077)	--	--
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 16,555	$ (945,931)	$ (31,574)	$ (183,377)
EARNINGS (LOSS) PER COMMON SHARE:				
EARNINGS (LOSS) PER COMMON SHARE-BASIC:				
Income (loss) before extraordinary item	$ 0.17	$ (9.83)	$ (0.45)	$ (2.69)
Extraordinary item	--	(0.14)	--	(0.10)
Net income (loss)	$ 0.17	$ (9.97)	$ (0.45)	$ (2.79)
EARNINGS (LOSS) PER COMMON SHARE-ASSUMING DILUTION:				
Income (loss) before extraordinary item	$ 0.16	$ (9.83)	$ (0.45)	$ (2.69)
Extraordinary item	--	(0.14)	--	(0.10)
Net income (loss)	$ 0.16	$ (9.97)	$ (0.45)	$ (2.79)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (IN 000'S):				
Basic	97,077	94,911	70,835	65,767
Assuming dilution	102,038	94,911	70,835	65,767

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	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
NET INCOME (LOSS)	$ 33,266	$ (933,854)	$ (31,574)	$ (183,377)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:				
Depreciation, depletion and amortization	99,516	152,204	62,028	105,591
Impairment of oil and gas assets	--	826,000	110,000	236,000
Impairment of other assets	--	55,000	--	--
Deferred taxes	1,764	--	--	(3,573)
Amortization of loan costs	3,338	2,516	794	1,455
Amortization of bond discount	84	98	41	217
Bad debt expense	9	1,589	40	299
Gain on sale of Bayard stock	--	--	(73,840)	--
Gain on sale of fixed assets	(459)	(90)	(209)	(1,593)
Extraordinary loss	--	13,334	--	6,620
Equity in (earnings) losses from investments and other	1,209	703	592	(499)
Cash provided by operating activities before changes in current assets and liabilities	138,727	117,500	67,872	161,140
CHANGES IN ASSETS AND LIABILITIES:				
(Increase) decrease in short-term investments	--	12,027	92,127	(102,858)
(Increase) decrease in accounts receivable	17,592	12,191	(7,173)	(19,987)
(Increase) decrease in inventory	743	168	(1,584)	(1,467)
(Increase) decrease in other current assets	3,614	7,637	(1,519)	1,466
Increase (decrease) in accounts payable, accrued liabilities and other	(23,891)	(46,785)	(11,044)	48,085
Increase (decrease) in current and non-current revenues and royalties due others	3,517	(8,099)	478	(2,290)
Increase (decrease) in deferred income taxes	4,720	--	--	--
Changes in assets and liabilities	6,295	(22,861)	71,285	(77,051)
Cash provided by operating activities	145,022	94,639	139,157	84,089
CASH FLOWS FROM INVESTING ACTIVITIES:				
Exploration and development of oil and gas properties	(153,268)	(259,710)	(187,252)	(465,367)
Acquisitions of oil and gas companies and properties, net of cash acquired	(49,893)	(279,924)	--	--
Divestitures of oil and gas properties	45,635	15,712	--	--
Investment in preferred stock of Gothic Energy Corporation	--	(39,500)	--	--
Net proceeds from sale of Bayard stock	--	--	90,380	--
Repayment of note receivable	--	2,000	18,000	--
Proceeds from sale of investment in PanEast	--	21,245	--	--
Other proceeds from sales	5,530	3,600	17	6,428
Long-term loans made to third parties	--	--	--	(20,000)
Investment in oil field service company	--	--	(200)	(3,048)
Increase in deferred charges	(5,865)	--	--	--
Other investments	(730)	--	(30,434)	(8,000)
Other property and equipment additions	(1,182)	(11,473)	(27,015)	(33,867)
Cash used in investing activities	(159,773)	(548,050)	(136,504)	(523,854)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from issuance of common stock	--	--	--	288,091
Proceeds from long-term borrowings	116,500	658,750	--	342,626
Payments on long-term borrowings	(98,000)	(474,166)	--	(119,581)
Dividends paid on common stock	--	(5,592)	(2,810)	--
Dividends paid on preferred stock	--	(8,050)	--	--
Proceeds from issuance of preferred stock	--	222,663	--	--
Purchase of treasury stock and preferred stock	(53)	(29,962)	--	--
Cash received from exercise of stock options	520	154	322	1,387
Other financing	--	--	(322)	(379)
Cash provided by (used in) financing activities	18,967	363,797	(2,810)	512,144
EFFECT OF EXCHANGE RATE CHANGES ON CASH	4,922	(4,726)	--	--
Net increase (decrease) in cash and cash equivalents	9,138	(94,340)	(157)	72,379
Cash and cash equivalents, beginning of period	29,520	123,860	124,017	51,638
Cash and cash equivalents, end of period	$ 38,658	$ 29,520	$ 123,860	$ 124,017

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	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS)			
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION				
CASH PAYMENTS FOR:				
Interest, net of capitalized interest	$ 80,684	$ 59,881	$ 17,367	$ 12,919
Income taxes	$ --	$ --	$ 500	$ --
DETAILS OF ACQUISITION OF ANSON PRODUCTION CORPORATION:				
Fair value of assets acquired	$ --	$ --	$ 43,000	$ --
Accrued liability for estimated cash consideration	$ --	$ --	$ (15,500)	$ --
Stock issued (3,792,724 shares)	$ --	$ --	$ (27,500)	$ --
DETAILS OF ACQUISITION OF DLB OIL & GAS, INC.:				
Fair value of assets acquired	$ --	$ 136,500	$ --	$ --
Cash consideration	$ --	$ (17,500)	$ --	$ --
Stock issued (5,000,000 shares)	$ --	$ (30,000)	$ --	$ --
Debt assumed	$ --	$ (85,000)	$ --	$ --
Acquisition costs paid	$ --	$ (4,000)	$ --	$ --
DETAILS OF ACQUISITION OF HUGOTON ENERGY CORPORATION:				
Fair value of assets acquired	$ --	$ 343,371	$ --	$ --
Stock options granted	$ --	$ (2,050)	$ --	$ --
Stock issued (25,790,146 shares)	$ --	$ (206,321)	$ --	$ --
Debt assumed	$ --	$ (120,000)	$ --	$ --
Acquisition costs paid	$ --	$ (15,000)	$ --	$ --

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

In November 1999, the Chief Executive Officer and Chief Operating Officer of Chesapeake tendered to Chesapeake Energy Marketing, Inc. ("CEMI") 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.

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

The Company had a financing arrangement with a vendor to supply certain oil and gas equipment inventory, which was terminated during the Transition Period. The total amount owed at June 30, 1997 was $1,380,000. No cash consideration is exchanged for inventory under this financing arrangement until actual draws on the inventory are made.

In fiscal 1997, the Company recognized income tax benefits of $4,808,000 related to the disposition of stock options by directors and employees of the Company. The tax benefits were recorded as an adjustment to deferred income taxes and paid-in capital.

Proceeds from the issuance of $500 million of 9.625% senior notes in April 1998 and $300 million of senior notes ($150 million of 7.875% senior notes and $150 million of 8.5% senior notes) in March 1997, are net of $11.7 million and $6.4 million, respectively, in offering fees and expenses which were deducted from the actual cash received.

On December 22, 1997, the Company declared a dividend of $0.02 per common share, or $1,486,000, which was paid on January 15, 1998. On June 13, 1997 the Company declared a dividend of $0.02 per common share, or $1,405,000, which was paid on July 15, 1997.

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT) AND COMPREHENSIVE INCOME (LOSS)

	YEARS ENDED DECEMBER 31, 1999	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS)			
PREFERRED STOCK:				
Balance, beginning of period	$ 230,000	$ --	$ --	$ --
Purchase of preferred stock	(180)	--	--	--
Issuance of preferred stock	--	230,000	--	--
Balance, end of period	229,820	230,000	--	--
COMMON STOCK:				
Balance, beginning of period	1,052	743	703	3,008
Issuance of 8,972,000 shares of common stock	--	--	--	90
Exercise of stock options and warrants	6	--	2	12
Issuance of 3,792,724 shares of common stock to AnSon Production Corporation	--	--	38	--
Issuance of 25,790,146 shares of common stock to Hugoton Energy Corporation	--	258	--	--
Issuance of 5,000,000 shares of common stock to DLB Oil and Gas, Inc.	--	50	--	--
Change in par value and other	1	1	--	(2,407)
Balance, end of period	1,059	1,052	743	703
PAID-IN CAPITAL:				
Balance, beginning of period	682,263	460,770	432,991	136,782
Exercise of stock options and warrants	514	153	320	1,375
Issuance of common stock	--	236,013	27,459	301,593
Offering expenses and other	1	(16,723)	--	(13,974)
Stock options issued in Hugoton purchase	--	2,050	--	--
Purchase of preferred stock at discount	127	--	--	--
Tax benefit from exercise of stock options	--	--	--	4,808
Change in par value	--	--	--	2,407
Balance, end of period	682,905	682,263	460,770	432,991
ACCUMULATED EARNINGS (DEFICIT):				
Balance, beginning of period	(1,127,195)	(181,270)	(146,805)	37,977
Net income (loss)	33,266	(933,854)	(31,574)	(183,377)
Dividends on common stock	--	(4,021)	(2,891)	(1,405)
Dividends on preferred stock	--	(8,050)	--	--
Balance, end of period	(1,093,929)	(1,127,195)	(181,270)	(146,805)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):				
Balance, beginning of period	(4,726)	(37)	--	--
Foreign currency translation adjustments	4,922	(4,689)	(37)	--
Balance, end of period	196	(4,726)	(37)	--
TREASURY STOCK - COMMON:				
Balance, beginning of period	(29,962)	--	--	--
Exchange of notes receivable for common stock from related parties	(7,633)	(29,962)	--	--
Balance, end of period	(37,595)	(29,962)	--	--
TOTAL STOCKHOLDERS' EQUITY (DEFICIT)	$ (217,544)	$ (248,568)	$ 280,206	$ 286,889
COMPREHENSIVE INCOME (LOSS):				
Net income (loss)	$ 33,266	$ (933,854)	$ (31,574)	$ (183,377)
Other comprehensive income (loss) - foreign currency translation adjustments	4,922	(4,689)	(37)	--
Comprehensive income (loss)	$ 38,188	$ (938,543)	$ (31,611)	$ (183,377)

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

The Company is an oil and natural gas exploration and production company engaged in the acquisition, exploration, and development of properties for the production of crude oil and natural gas from underground reservoirs. The Company's properties are located in Oklahoma, Texas, Arkansas, Louisiana, Kansas, Montana, Colorado, North Dakota, New Mexico and British Columbia and Saskatchewan, Canada.

These consolidated financial statements relate to the years ended December 31, 1999 ("1999"), December 31, 1998 ("1998") and June 30, 1997 ("fiscal 1997"). The Company changed its fiscal year end from June 30 to December 31 in 1997. The Company's results of operations and cash flows for the six months ended December 31, 1997 (the "Transition Period") are also included in these consolidated financial statements.

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation include the accounts of its direct and indirect wholly-owned subsidiaries (the "Company"). All significant intercompany accounts and transactions have been eliminated. Investments in companies and partnerships which give the Company significant influence, but not control, over the investee are accounted for using the equity method.

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, the Company considers investments in all highly liquid debt instruments with maturities of three months or less at date of purchase to be cash equivalents.

Investments in Securities

The Company invests in various equity securities and short-term debt instruments including corporate bonds and auction preferreds, commercial paper and government agency notes. The Company has classified all of its short-term investments in equity and debt instruments as trading securities, which are carried at fair value with unrealized holding gains and losses included in earnings. Investments in equity securities and limited partnerships that do not have readily determinable fair values are stated at cost and are included in noncurrent other assets. In determining realized gains and losses, the cost of securities sold is based on the average cost method.

Inventory

Inventory consists primarily of tubular goods and other lease and well equipment which the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market using the specific identification method.

Oil and Gas Properties

The Company follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. The Company capitalizes internal costs that can be directly identified with its acquisition, exploration and development activities and does 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, 1999, approximately 66% of the Company's proved reserve value (based on SEC PV10%) was evaluated by independent petroleum engineers, with the balance evaluated by the Company's engineers. In addition, the company's engineers evaluate all properties quarterly. The average composite rates used for depreciation, depletion and amortization were $0.71 ($0.73 in U.S. and $0.52 in Canada) per equivalent Mcf in 1999, $1.13 ($1.17 in U.S. and $0.43 in Canada) per equivalent Mcf in 1998, $1.57 per equivalent Mcf in the Transition Period and $1.31 per equivalent Mcf in fiscal 1997. The Company did not have operations in Canada prior to 1998.

Proceeds from the sale of properties are accounted for as reductions to 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. The Company reviews all of its 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 assessed individually when individual costs are significant.

The Company reviews the carrying value of its 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. During 1998, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from the Company's proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $826 million. During the Transition Period, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $110 million. During fiscal 1997, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from the Company's proved reserves, net of related income tax considerations, resulting in a writedown in the carrying value of oil and gas properties of $236 million.

Other Property and Equipment

Other property and equipment consists primarily of gas gathering and processing facilities, 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. 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 1999, 1998, the Transition Period and fiscal 1997, interest of approximately $3.5 million, $6.5 million, $5.1 million and $12.9 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.

Income Taxes

The Company has adopted Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("SFAS 109"). 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 ("SFAS 128") requires presentation of "basic" and "diluted" earnings per share, as defined, on the face of the statement 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. For 1998, the Transition Period and fiscal 1997, there was no difference between actual weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares, which are used in computing diluted EPS. Options to purchase 12.9 million, 11.3 million, 8.3 million and 7.9 million shares of common stock at weighted average exercise prices of $1.76, $1.86, $5.49 and $7.09 were outstanding during 1999, 1998, the Transition Period and fiscal 1997 but were not included in the computation of diluted EPS because the effect of these outstanding options would be antidilutive. A reconciliation for 1999 is as follows:

	INCOME (NUMERATOR)	SHARES (DENOMINATOR)	PER SHARE AMOUNT
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

Gas Imbalances -- Revenue Recognition

Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. The Company follows the "sales method" of accounting for its gas revenue whereby the Company recognizes sales revenue on all gas sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A liability is recognized only to the extent that the Company has a net imbalance in excess of the remaining gas reserves on the underlying properties. The Company's net imbalance positions at December 31, 1999 and 1998 were not material.

Hedging

The Company periodically uses certain instruments to hedge its exposure to price fluctuations on 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 the Company's oil and gas production, in oil and gas marketing sales to the extent related to the Company's marketing activities, and in interest expense to the extent so related.

Debt Issue Costs

Included in other assets are costs associated with the issuance of the senior notes. The remaining unamortized costs on these issuances of senior notes at December 31, 1999 totaled $16.6 million and are being amortized over the life of the senior notes.

Comprehensive Income

In 1998, the Company adopted SFAS No. 130, Reporting Comprehensive Income. This statement establishes rules for the reporting of comprehensive income and its components. Comprehensive income consists of net income and foreign currency translation adjustments and is presented in the Consolidated Statements of Stockholders' Equity (Deficit) and Comprehensive Income (Loss). The adoption of SFAS 130 had no impact on total stockholders' equity. Prior year financial statements have been reclassified to conform to the SFAS 130 requirements. All balance sheet accounts of foreign operations are translated into U.S. dollars at the year-end rate of exchange and statement of operations items are translated at the weighted average exchange rates for the year.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for 1998, the Transition Period, and fiscal 1997 to conform to the presentation used for the 1999 consolidated financial statements.

2. SENIOR NOTES

On April 22, 1998, the Company issued $500 million principal amount of 9.625% Senior Notes due 2005 ("9.625% Senior Notes"). The 9.625% Senior Notes are redeemable at the option of the Company at any time on or after May 1, 2002 at the redemption prices set forth in the indenture or at the make-whole prices, as set forth in the indenture, if redeemed prior to May 1, 2002. The Company may also redeem at its option up to $167 million of the 9.625% Senior Notes at 109.625% of their principal amount with the proceeds of an equity offering completed prior to May 1, 2001.

On March 17, 1997, the Company issued $150 million principal amount of 7.875% Senior Notes due 2004 ("7.875% Senior Notes"). The 7.875% Senior Notes are redeemable at the option of the Company at any time prior to March 15, 2004 at the make-whole prices determined in accordance with the indenture.

Also on March 17, 1997, the Company issued $150 million principal amount of 8.5% Senior Notes due 2012 ("8.5% Senior Notes"). The 8.5% Senior Notes are redeemable at the option of the Company 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 therein.

On April 9, 1996, the Company issued $120 million principal amount of 9.125% Senior Notes due 2006 ("9.125% Senior Notes"). The 9.125% Senior Notes are redeemable at the option of the Company at any time prior to April 15, 2001 at the make-whole prices determined in accordance with the indenture and, on or after April 15, 2001 at the redemption prices set forth therein.

On May 25, 1995, the Company issued $90 million principal amount of 10.5% Senior Notes due 2002 ("10.5% Senior Notes"). In April 1998, the Company purchased all of its 10.5% Senior Notes for approximately $99 million. The early retirement of these notes resulted in an extraordinary charge of $13.3 million.

The Company is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. The Company's obligations under the 9.625% Senior Notes, the 9.125% 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 the Company's "Restricted Subsidiaries" (as defined in the respective indentures governing the Senior Notes) (collectively, the "Guarantor Subsidiaries"). Each of the Guarantor Subsidiaries is a direct or indirect wholly-owned subsidiary of the Company.

The senior note indentures contain certain covenants, including covenants limiting the Company 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 Company is obligated to repurchase the 9.625% and 9.125% Senior Notes in the event of a change of control or certain asset sales.

The senior note indentures also limit the Company's ability to make restricted payments (as defined), including the payment of preferred stock dividends, unless certain tests are met. From December 31, 1998 through December 31, 1999, the Company was unable to meet the requirements to incur additional unsecured indebtedness, and consequently was not able to pay cash dividends on its 7% cumulative convertible preferred stock. The Company had accumulated dividends in arrears of $19.3 million related to its preferred stock as of February 29, 2000. Subsequent payments will be subject to the same restrictions and are dependent upon variables that are beyond the Company's ability to predict. This restriction does not affect the Company's ability to borrow under or expand its secured commercial bank facility. If the Company fails to pay dividends for six quarterly periods, the holders of preferred stock will be entitled to elect two new directors to the Board. Based on current projections of cash flow and fixed charges, the Company does not expect to be able to pay a dividend on the preferred stock on May 1, 2000, which would be the sixth consecutive dividend payment date on which dividends have not been paid.

Set forth below are condensed consolidating financial statements of the Guarantor Subsidiaries, the Company's subsidiaries which are not guarantors of the Senior Notes (the "Non-Guarantor Subsidiaries") and the Company. Separate audited financial statements of each Guarantor Subsidiary have not been provided because management has determined that they are not material to investors.

Chesapeake Energy Marketing, Inc. ("CEMI") was a Non-Guarantor Subsidiary for all periods presented. The following were additional Non-Guarantor Subsidiaries: Chesapeake Acquisition Corporation during the Transition Period and Chesapeake Canada Corporation during fiscal 1997. All of the Company's other subsidiaries were Guarantor Subsidiaries during all periods presented.

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 1999
($ IN THOUSANDS)

ASSETS

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
CURRENT ASSETS:					
Cash and cash equivalents	$ (6,964)	$ 20,409	$ 25,405	$ --	$ 38,850
Accounts receivable	45,170	18,297	73	(12,475)	51,065
Inventory	4,183	399	--	--	4,582
Other	1,997	700	352	--	3,049
Total Current Assets	44,386	39,805	25,830	(12,475)	97,546
PROPERTY AND EQUIPMENT:					
Oil and gas properties	2,311,633	3,715	--	--	2,315,348
Unevaluated leasehold	40,008	--	--	--	40,008
Other property and equipment	29,088	20,521	18,103	--	67,712
Less: accumulated depreciation, depletion and amortization	(1,683,890)	(18,205)	(1,876)	--	(1,703,971)
Net Property and Equipment ...	696,839	6,031	16,227	--	719,097
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	806,180	--	493,738	(1,299,918)	--
OTHER ASSETS	16,402	8,409	16,765	(7,686)	33,890
TOTAL ASSETS	$ 1,563,807	$ 54,245	$ 552,560	$ (1,320,079)	$ 850,533

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ --	$ 763	$ --	$ --	$ 763
Accounts payable and other	63,194	19,265	17,466	(12,502)	87,423
Total Current Liabilities	63,194	20,028	17,466	(12,502)	88,186
LONG-TERM DEBT	43,500	1,437	919,160	--	964,097
REVENUES AND ROYALTIES DUE OTHERS	9,310	--	--	--	9,310
DEFERRED INCOME TAXES	6,484	--	--	--	6,484
INTERCOMPANY PAYABLES	1,356,466	(2,450)	(1,354,043)	27	--
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	27	1	1,048	(17)	1,059
Other	84,826	35,229	968,929	(1,307,587)	(218,603)
	84,853	35,230	969,977	(1,307,604)	(217,544)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 1,563,807	$ 54,245	$ 552,560	$ (1,320,079)	$ 850,533

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 1998
($ IN THOUSANDS)

ASSETS

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
CURRENT ASSETS:					
Cash and cash equivalents	$ (11,565)	$ 7,000	$ 39,839	$ --	$ 35,274
Accounts receivable	54,384	29,641	270	(7,996)	76,299
Inventory	4,919	406	--	--	5,325
Other	721	15	365	--	1,101
Total Current Assets	48,459	37,062	40,474	(7,996)	117,999
PROPERTY AND EQUIPMENT:					
Oil and gas properties	2,142,943	--	--	--	2,142,943
Unevaluated leasehold	52,687	--	--	--	52,687
Other property and equipment	47,628	15,109	16,981	--	79,718
Less: accumulated depreciation, depletion and amortization	(1,601,931)	(8,036)	(1,390)	--	(1,611,357)
Net Property and Equipment	641,327	7,073	15,591	--	663,991
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	473,578	--	481,150	(954,728)	--
OTHER ASSETS	10,610	560	19,455	--	30,625
TOTAL ASSETS	$ 1,173,974	$ 44,695	$ 556,670	$ (962,724)	$ 812,615

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 25,000	$ --	$ --	$ --	$ 25,000
Accounts payable and other	80,786	15,992	17,529	(8,023)	106,284
Total Current Liabilities	105,786	15,992	17,529	(8,023)	131,284
LONG-TERM DEBT	--	--	919,076	--	919,076
REVENUES AND ROYALTIES DUE OTHERS	10,823	--	--	--	10,823
DEFERRED INCOME TAXES	--	--	--	--	--
INTERCOMPANY PAYABLES	1,338,948	11,376	(1,350,351)	27	--
STOCKHOLDERS' EQUITY (DEFICIT):					
Common Stock	26	1	1,042	(17)	1,052
Other	(281,609)	17,326	969,374	(954,711)	(249,620)
	(281,583)	17,327	970,416	(954,728)	(248,568)
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 1,173,974	$ 44,695	$ 556,670	$ (962,724)	$ 812,615

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1999:					
REVENUES:					
Oil and gas sales	$ 279,740	$ --	$ --	$ 705	$ 280,445
Oil and gas marketing sales	--	194,605	--	(120,104)	74,501
Total Revenues	279,740	194,605	--	(119,399)	354,946
OPERATING COSTS:					
Production expenses and taxes	59,158	404	--	--	59,562
Oil and gas marketing expenses	--	190,932	--	(119,399)	71,533
Impairment of oil and gas properties	--	--	--	--	--
Impairment of other assets	--	--	--	--	--
Oil and gas depreciation, depletion and amortization	94,649	395	--	--	95,044
Other depreciation and amortization	4,474	80	3,256	--	7,810
General and administrative	12,143	1,251	83	--	13,477
Total Operating Costs	170,424	193,062	3,339	(119,399)	247,426
INCOME (LOSS) FROM OPERATIONS	109,316	1,543	(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)
	(79,595)	4,727	2,378	--	(72,490)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	29,721	6,270	(961)	--	35,030
INCOME TAX EXPENSE (BENEFIT)	1,764	--	--	--	1,764
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	27,957	6,270	(961)	--	33,266
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	--	--	--	--	--
NET INCOME (LOSS)	$ 27,957	$ 6,270	$ (961)	$ --	$ 33,266

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1998:					
REVENUES:					
Oil and gas sales	$ 254,541	$ --	$ --	$ 2,346	$ 256,887
Oil and gas marketing sales	--	225,195	--	(104,136)	121,059
Total Revenues	254,541	225,195	--	(101,790)	377,946
OPERATING COSTS:					
Production expenses and taxes	59,497	--	--	--	59,497
Oil and gas marketing expenses	--	220,798	--	(101,790)	119,008
Impairment of oil and gas properties	826,000	--	--	--	826,000
Impairment of other assets	47,000	8,000	--	--	55,000
Oil and gas depreciation, depletion and amortization	146,644	--	--	--	146,644
Other depreciation and amortization	5,204	126	2,746	--	8,076
General and administrative	18,081	1,766	71	--	19,918
Total Operating Costs	1,102,426	230,690	2,817	(101,790)	1,234,143
INCOME (LOSS) FROM OPERATIONS	(847,885)	(5,495)	(2,817)	--	(856,197)
OTHER INCOME (EXPENSE):					
Interest and other income	649	2,259	100,886	(99,868)	3,926
Interest expense	(96,214)	(382)	(71,521)	99,868	(68,249)
	(95,565)	1,877	29,365	--	(64,323)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(943,450)	(3,618)	26,548	--	(920,520)
INCOME TAX EXPENSE (BENEFIT)	--	--	--	--	--
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(943,450)	(3,618)	26,548	--	(920,520)
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(2,164)	--	(11,170)	--	(13,334)
NET INCOME (LOSS)	$ (945,614)	$ (3,618)	$ 15,378	$ --	$ (933,854)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE SIX MONTHS ENDED DECEMBER 31, 1997:					
REVENUES:					
Oil and gas sales	$ 93,384	$ 1,199	$ --	$ 1,074	$ 95,657
Oil and gas marketing sales	--	101,689	--	(43,448)	58,241
Total Revenues	93,384	102,888	--	(42,374)	153,898
OPERATING COSTS:					
Production expenses and taxes	9,905	189	--	--	10,094
Oil and gas marketing expenses	--	100,601	--	(42,374)	58,227
Impairment of oil and gas properties	96,000	14,000	--	--	110,000
Oil and gas depreciation, depletion and amortization	59,758	650	--	--	60,408
Other depreciation and amortization	1,383	40	991	--	2,414
General and administrative	4,598	1,132	117	--	5,847
Total Operating Costs	171,644	116,612	1,108	(42,374)	246,990
INCOME (LOSS) FROM OPERATIONS	(78,260)	(13,724)	(1,108)	--	(93,092)
OTHER INCOME (EXPENSE):					
Interest and other income	515	192	110,751	(32,492)	78,966
Interest expense	(27,481)	(39)	(22,420)	32,492	(17,448)
	(26,966)	153	88,331	--	61,518
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(105,226)	(13,571)	87,223	--	(31,574)
INCOME TAX EXPENSE (BENEFIT)	--	--	--	--	--
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(105,226)	(13,571)	87,223	--	(31,574)
EXTRAORDINARY ITEM	--	--	--	--	--
NET INCOME (LOSS)	$ (105,226)	$ (13,571)	$ 87,223	$ --	$ (31,574)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED JUNE 30, 1997:					
REVENUES:					
Oil and gas sales	$ 191,303	$ --	$ --	$ 1,617	$ 192,920
Oil and gas marketing sales	--	145,942	--	(69,770)	76,172
Total Revenues	191,303	145,942	--	(68,153)	269,092
OPERATING COSTS:					
Production expenses and taxes	15,107	--	--	--	15,107
Oil and gas marketing expenses	--	143,293	--	(68,153)	75,140
Impairment of oil and gas properties	236,000	--	--	--	236,000
Oil and gas depreciation, depletion and amortization	103,264	--	--	--	103,264
Other depreciation and amortization	2,152	80	1,550	--	3,782
General and administrative	6,313	921	1,568	--	8,802
Total Operating Costs	362,836	144,294	3,118	(68,153)	442,095
INCOME (LOSS) FROM OPERATIONS	(171,533)	1,648	(3,118)	--	(173,003)
OTHER INCOME (EXPENSE):					
Interest and other income	778	749	49,224	(39,528)	11,223
Interest expense	(37,644)	(10)	(20,424)	39,528	(18,550)
	(36,866)	739	28,800	--	(7,327)
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(208,399)	2,387	25,682	--	(180,330)
INCOME TAX EXPENSE (BENEFIT)	(4,129)	47	509	--	(3,573)
NET INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(204,270)	2,340	25,173	--	(176,757)
EXTRAORDINARY ITEM:					
Loss on early extinguishment of debt, net of applicable income tax	(769)	--	(5,851)	--	(6,620)
NET INCOME (LOSS)	$ (205,039)	$ 2,340	$ 19,322	$ --	$ (183,377)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1999:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 135,303	$ 7,193	$ 2,526	$ --	$ 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	(5,777)	(72)	(1,198)	--	(7,047)
	(164,063)	5,488	(1,198)	--	(159,773)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	116,500	--	--	--	116,500
Payments on long-term borrowings	(98,000)	--	--	--	(98,000)
Cash paid for purchase of preferred stock	--	(53)	--	--	(53)
Exercise of stock options	--	--	520	--	520
Intercompany advances, net	15,501	781	(16,282)	--	--
	34,001	728	(15,762)	--	18,967
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 SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1998:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 66,960	$ (13,137)	$ 40,816	$ --	$ 94,639
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(523,922)	--	--	--	(523,922)
Proceeds from sale of assets	--	--	3,600	--	3,600
Investment in preferred stock of Gothic Energy Corporation	(39,500)	--	--	--	(39,500)
Repayment of note receivable	2,000	--	--	--	2,000
Proceeds from sale of PanEast Petroleum Corporation	--	--	21,245	--	21,245
Other additions	(2,510)	8,408	(17,371)	--	(11,473)
	(563,932)	8,408	7,474	--	(548,050)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	--	--	658,750	--	658,750
Payments on long-term borrowings	--	--	(474,166)	--	(474,166)
Cash received from issuance of preferred stock	--	--	222,663	--	222,663
Cash paid for purchase of treasury stock	--	--	(29,962)	--	(29,962)
Dividends paid on common stock and preferred stock	--	--	(13,642)	--	(13,642)
Exercise of stock options	--	--	154	--	154
Intercompany advances, net	476,663	6,035	(482,698)	--	--
	476,663	6,035	(118,901)	--	363,797
EFFECT OF EXCHANGE RATE CHANGES ON CASH	(4,726)	--	--	--	(4,726)
Net increase (decrease) in cash and cash Equivalents	(25,035)	1,306	(70,611)	--	(94,340)
Cash, beginning of period	(284)	13,694	110,450	--	123,860
Cash, end of period	$ (25,319)	$ 15,000	$ 39,839	$ --	$ 29,520

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE SIX MONTHS ENDED DECEMBER 31, 1997:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 28,598	$ (10,842)	$ 121,401	$ --	$ 139,157
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(187,252)	--	--	--	(187,252)
Investment in service operations	(200)	--	--	--	(200)
Other investments	(26,472)	--	99,380	--	72,908
Other additions	(22,864)	1,357	(453)	--	(21,960)
	(236,788)	1,357	98,927	--	(136,504)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Dividends paid on common stock	--	--	(2,810)	--	(2,810)
Exercise of stock options	--	--	322	--	322
Other financing	--	(322)	--	--	(322)
Intercompany advances, net	214,135	19,443	(233,578)	--	--
	214,135	19,121	(236,066)	--	(2,810)
Net increase (decrease) in cash and cash Equivalents	5,945	9,636	(15,738)	--	(157)
Cash, beginning of period	(6,534)	4,363	126,188	--	124,017
Cash, end of period	$ (589)	$ 13,999	$ 110,450	$ --	$ 123,860

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED JUNE 30, 1997:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 165,850	$ (11,008)	$ (70,753)	$ --	$ 84,089
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(465,424)	57	--	--	(465,367)
Proceeds from sale of assets	6,428	--	--	--	6,428
Investment in service operations	(3,048)	--	--	--	(3,048)
Long-term loans to third parties	(2,000)	--	(18,000)	--	(20,000)
Other investments	--	--	(8,000)	--	(8,000)
Other additions	(24,318)	(1,999)	(7,550)	--	(33,867)
	(488,362)	(1,942)	(33,550)	--	(523,854)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	50,000	--	292,626	--	342,626
Payments on borrowings	(118,901)	--	(680)	--	(119,581)
Exercise of stock options	--	--	1,387	--	1,387
Issuance of common stock	--	--	288,091	--	288,091
Other financing	--	--	(379)	--	(379)
Intercompany advances, net	380,735	14,645	(395,380)	--	--
	311,834	14,645	185,665	--	512,144
Net increase (decrease) in cash and cash equivalents	(10,678)	1,695	81,362	--	72,379
Cash, beginning of period	4,144	2,668	44,826	--	51,638
Cash, end of period	$ (6,534)	$ 4,363	$ 126,188	$ --	$ 124,017

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

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARIES	COMPANY	ELIMINATIONS	CONSOLIDATED
FOR THE YEAR ENDED DECEMBER 31, 1999:					
Net income (loss)	$ 27,957	$ 6,270	$ (961)	$ --	$ 33,266
Other comprehensive income (loss) - foreign currency translation	4,922	--	--	--	4,922
Comprehensive income	$ 32,879	$ 6,270	$ (961)	$ --	$ 38,188
FOR THE YEAR ENDED DECEMBER 31, 1998:					
Net income (loss)	$ (945,614)	$ (3,618)	$ 15,378	$ --	$ (933,854)
Other comprehensive income (loss) - foreign currency translation	(4,689)	--	--	--	(4,689)
Comprehensive income (loss)	$ (950,303)	$ (3,618)	$ 15,378	$ --	$ (938,543)
FOR THE SIX MONTHS ENDED DECEMBER 31, 1997:					
Net income (loss)	$ (105,226)	$ (13,571)	$ 87,223	$ --	$ (31,574)
Other comprehensive income (loss) - foreign currency translation	(37)	--	--	--	(37)
Comprehensive income (loss)	$ (105,263)	$ (13,571)	$ 87,223	$ --	$ (31,611)
FOR THE YEAR ENDED JUNE 30, 1997:					
Net income (loss)	$ (205,039)	$ 2,340	$ 19,322	$ --	$ (183,377)
Other comprehensive income (loss) - foreign currency translation	--	--	--	--	--
Comprehensive income (loss)	$ (205,039)	$ 2,340	$ 19,322	$ --	$ (183,377)

3. NOTES PAYABLE AND LONG-TERM DEBT

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

	DECEMBER 31, 1999	DECEMBER 31, 1998
	($ IN THOUSANDS)	
7.875% Senior Notes (see Note 2)	$ 150,000	$ 150,000
Discount on 7.875% Senior Notes	(73)	(90)
8.5% Senior Notes (see Note 2)	150,000	150,000
Discount on 8.5% Senior Notes	(715)	(774)
9.125% Senior Notes (see Note 2)	120,000	120,000
Discount on 9.125% Senior Notes	(52)	(60)
9.625% Senior Notes (see Note 2)	500,000	500,000
Note payable	2,200	--
Other collateralized	43,500	25,000
Total notes payable and long-term debt	964,860	944,076
Less-- current maturities	(763)	(25,000)
Notes payable and long-term debt, net of current maturities	$ 964,097	$ 919,076

The aggregate scheduled maturities of notes payable and long-term debt for the next five fiscal years ending December 31, 2004 and thereafter were as follows as of December 31, 1999 (in thousands of dollars):

2000	$ 763
2001	44,336
2002	601
2003	--
2004	149,927
After 2004	769,233
	$ 964,860

4. CONTINGENCIES AND COMMITMENTS

Bayard Securities Litigation

A purported class action alleging violations of the Securities Act of 1933 and the Oklahoma Securities Act was first filed in February 1998 against the Company and others on behalf of investors who purchased common stock of Bayard Drilling Technologies, Inc. ("Bayard") in, or traceable to, its initial public offering in November 1997. Total proceeds of the offering were $254 million, of which the Company received net proceeds of $90 million as a selling shareholder. Plaintiffs allege that the Company, a major customer of Bayard's drilling services and the owner of 30.1% of Bayard's common stock outstanding prior to the offering, was a controlling person of Bayard. Alleged defective disclosures are claimed to have resulted in a decline in Bayard's share price following the public offering. Plaintiffs seek a determination that the suit is a proper class action and damages in an unspecified amount or rescission, together with interest and costs of litigation, including attorneys' fees.

On August 24, 1999, the court dismissed plaintiffs' claims against the Company under Section 15 of the Securities Act of 1933 alleging that the Company was a "controlling person" of Bayard. Claims under Section 11 of the Securities Act of 1933 and Section 408 of the Oklahoma Securities Act continue to be asserted against the Company. The Company believes that it has meritorious defenses to these claims and intends to defend this action vigorously. No estimate of loss or range of estimate of loss, if any, can be made at this time. Bayard, which was acquired by Nabors Industries, Inc. in April 1999, has been reimbursing the Company for its costs of defense as incurred.

Patent Litigation

On September 21, 1999, judgment was entered in favor of the Company in a patent infringement lawsuit tried to the U.S. District Court for the Northern District of Texas, Fort Worth Division. Filed in October 1996, the lawsuit asserted that the Company had infringed a patent belonging to Union Pacific Resources Company. The court declared the patent invalid, held that the Company could not have infringed the patent, dismissed all of UPRC's claims with prejudice and assessed court costs against UPRC. Appeals of the judgment by both the Company and UPRC are pending in the Federal Circuit Court of Appeals. The Company has appealed the trial court's ruling denying the Company's request for attorneys' fees. Management is unable to predict the outcome of these appeals but believes the invalidity of the patent will be upheld on appeal.

West Panhandle Field Cessation Cases

A subsidiary of the Company, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. are defendants in 13 lawsuits filed between June 1997 and January 1999 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. The Company acquired MC Panhandle, Inc. on April 28, 1998. MC Panhandle, Inc. has owned the leases since January 1, 1997, and the co-defendants are prior lessees. Plaintiffs claim the leases terminated upon the cessation of production for various periods primarily during the 1960s. In addition, plaintiffs seek to recover conversion damages, exemplary damages, attorneys' fees and interest. Defendants assert that any cessation of production was excused and have pled affirmative defenses of limitations, waiver, temporary estoppel, laches and title by adverse possession.

Of the ten cases filed in the District Court of Moore County, Texas, 69th Judicial District, three have been tried to a jury. Judgment has been entered against CP and its co-defendants in all three cases, although there was a jury verdict in two of the cases in favor of defendants. The Company's aggregate liability for these judgments is $1.3 million of actual damages and $1.2 million of exemplary damages and, jointly and severally with the other two defendants, $1.5 million of actual damages and $337,000 of attorneys' fees in the event of an appeal, sanctions, interest and court costs. The court also quieted title to the leases in dispute in plaintiffs. CP and the other defendants have each appealed the judgments and posted supersedeas bonds in two of these cases and post-trial motions are pending in the other one. One of the other Moore County, Texas cases has been set for trial in May 2000. There are three related cases pending in other courts. One is set for trial in June 2000, and another, in the U.S. District Court, Northern District of Texas, Amarillo Division, resulted in a jury verdict for CP and its co-defendants. Judgment has not yet been entered in this case.

The Company has previously established an accrued liability that management believes will be sufficient to cover the estimated costs of litigation for each of these 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 other cases, the outcome of the remaining trials and the amount of damages that might ultimately be awarded could differ from management's estimates. Management believes, however, that the leases are valid, there is no basis for exemplary damages and that any findings of fraud or bad faith will be overturned on appeal. CP and the other defendants intend to vigorously defend against the plaintiffs' claims.

The Company is currently involved in various other routine disputes incidental to its business operations. While it is not possible to determine the ultimate disposition of these matters, 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 the Company.

The Company has employment contracts with its two principal shareholders and its chief financial officer and various other senior management personnel which provide for annual base salaries, bonus compensation and various benefits. The contracts provide for the continuation of salary and benefits for varying terms in the event of termination of employment without cause. These agreements expire at various times from June 30, 2000 through June 30, 2003.

Due to the nature of the oil and gas business, the Company and its subsidiaries are exposed to possible environmental risks. The Company has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. The Company is not aware of any potential material environmental issues or claims.

5. INCOME TAXES

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

	YEARS ENDED DECEMBER 31, 1999	1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS)			
Current	$ --	$ --	$ --	$ --
Deferred	1,764	--	--	(3,573)
Total	$ 1,764	$ --	$ --	$(3,573)

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

	YEARS ENDED DECEMBER 31, 1999	1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	($ IN THOUSANDS)			
Computed "expected" income tax provision (benefit)	$ 12,720	$(322,182)	$(11,051)	$(63,116)
Tax percentage depletion	(240)	(430)	(48)	(294)
Change in valuation allowance	(10,956)	380,969	13,818	64,116
State income taxes and other	240	(58,357)	(2,719)	(4,279)
	$ 1,764	$ --	$ --	$ (3,573)

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, 1999	1998
	($ IN THOUSANDS)	
Deferred tax liabilities:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$ (13,251)	$ --
Deferred tax assets:		
Acquisition, exploration and development costs and related depreciation, depletion and amortization	218,728	242,765
Net operating loss carryforwards	228,279	214,602
Percentage depletion carryforward	1,776	1,536
	448,783	458,903
Net deferred tax asset (liability)	435,532	458,903
Less: Valuation allowance	(442,016)	(458,903)
Total deferred tax asset (liability)	$ (6,484)	$ --

SFAS 109 requires that the Company record a valuation allowance when it is more likely than not that some portion or all of the deferred tax assets will not be realized. In 1998, the Company recorded an $826 million writedown related to the impairment of oil and gas properties. The writedown and significant tax net operating loss carryforwards (caused primarily by expensing intangible drilling costs for tax purposes) resulted in a net deferred tax asset at December 31, 1999 and 1998. The Company expects to generate future U.S. tax net operating losses for the foreseeable future. Management has determined that it is more likely than not that the net U.S. deferred tax assets will not be realized and has recorded a valuation allowance equal to the net U.S. deferred tax asset.

At December 31, 1998, $5.7 million of the valuation allowance was related to the Company's Canadian deferred tax assets. During 1999, this valuation allowance was eliminated as part of a purchase price reallocation related to a 1999 acquisition.

At December 31, 1999, the Company had a U.S. regular tax net operating loss carryforward of approximately $613 million and a U.S. alternative minimum tax net operating loss carryforward of approximately $267 million. The U.S. loss carryforward amounts will expire during the years 2007 through 2019. The Company also had a U.S. percentage depletion carryforward of approximately $5 million at

December 31, 1999, which is available to offset future U.S. federal income taxes payable and has no expiration date.

In accordance with certain provisions of the Tax Reform Act of 1986, a change of greater than 50% of the beneficial ownership of the Company within a three-year period (an "Ownership Change") would place an annual limitation on the Company's ability to utilize its existing tax carryforwards. Under regulations issued by the

Internal Revenue Service, the Company has had two Ownership Changes. However, these ownership changes have not resulted in a significant limitation of the tax carryforwards.

6. RELATED PARTY TRANSACTIONS

Certain directors, shareholders and employees of the Company have acquired working interests in certain of the Company's oil and gas properties. The owners of such working interests are required to pay their proportionate share of all costs. As of December 31, 1999 and 1998, the Company had accounts receivable from related parties, primarily related to such participation, of $4.6 million and $5.6 million, respectively.

As of December 31, 1998, the Chief Executive Officer and Chief Operating Officer of the Company had notes payable to CEMI in the principal amount of $9.9 million. In November 1999, the Chief Executive Officer and the Chief Operating Officer tendered to CEMI 2,320,107 shares of Chesapeake common stock in full satisfaction of the notes payable to CEMI with 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.

During 1999, 1998, the Transition Period and fiscal 1997, the Company incurred legal expenses of $398,000, $493,000, $388,000 and $207,000, respectively, for legal services provided by a law firm of which a director is a member.

7. EMPLOYEE BENEFIT PLANS

The Company maintains 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 are matched by the Company for up to 10% of the employee's annual salary with the Company's common stock purchased in the open-market. The amount of employee contribution is limited as specified in the plan. The Company may, at its discretion, make additional contributions to the plan. The Company contributed $1,163,000, $1,359,000, $418,000 and $603,000 to the plan during 1999, 1998, the Transition Period and fiscal 1997, 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,		AMOUNT ($ IN THOUSANDS)	PERCENT OF OIL AND GAS SALES
1999	Aquila Southwest Pipeline Corporation	$31,505	11%
1998	Koch Oil Company	$30,564	12%
	Aquila Southwest Pipeline Corporation	28,946	11
SIX MONTHS ENDED DECEMBER 31,			
1997	Aquila Southwest Pipeline Corporation	$20,138	21%
	Koch Oil Company	18,594	19
	GPM Gas Corporation	12,610	13
FISCAL YEAR ENDED JUNE 30,			
1997	Aquila Southwest Pipeline Corporation	$53,885	28%
	Koch Oil Company	29,580	15
	GPM Gas Corporation	27,682	14

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

The Company believes all of its material operations are part of the oil and gas industry, and therefore reports as a single industry segment. Beginning in 1998, the Company began foreign operations in Canada. The geographic distribution of the Company's revenue, operating income and identifiable assets are summarized below ($ in thousands):

	UNITED STATES	CANADA	CONSOLIDATED
1999:			
Revenue.........................	$ 340,969	$ 13,977	$ 354,946
Operating income (loss).........	103,188	4,332	107,520
Identifiable assets............	735,320	115,213	850,533
1998:			
Revenue.........................	$ 369,968	$ 7,978	$ 377,946
Operating income (loss).........	(842,798)	(13,399)	(856,197)
Identifiable assets............	724,713	87,902	812,615

9. STOCKHOLDERS' EQUITY AND STOCK BASED COMPENSATION

In November 1999, the Chief Executive Officer and the Chief Operating Officer of Chesapeake tendered to CEMI 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. See Note 6.

During 1998, the Company's Board of Directors approved the expenditure of up to $30 million to purchase outstanding Company common stock. As of August 25, 1998, the Company had purchased approximately 8.5 million shares of common stock for an aggregate amount of $30 million pursuant to such authorization.

On April 28, 1998, the Company acquired by merger the Mid-Continent operations of DLB Oil & Gas, Inc. ("DLB") for $17.5 million in cash, 5 million shares of the Company's common stock, and the assumption of $90 million in outstanding debt and working capital obligations.

On April 22, 1998, the Company issued $230 million (4.6 million shares) of its 7% Cumulative Convertible Preferred Stock, $50 per share liquidation preference, resulting in net proceeds to the Company of $223 million.

On March 10, 1998, the Company acquired Hugoton Energy Corporation ("Hugoton") pursuant to a merger by issuing approximately 25.8 million shares of the Company's common stock in exchange for 100% of Hugoton's common stock.

On December 16, 1997, the Company acquired AnSon Production Corporation. Consideration for this merger was approximately $43 million consisting of the issuance of approximately 3.8 million shares of Company common stock and cash consideration in accordance with the terms of the merger agreement.

On December 2, 1996, the Company completed a public offering of approximately 9.0 million shares of common stock at a price of $33.63 per share, resulting in net proceeds to the Company of approximately $288.1 million.

A 2-for-1 stock split of the common stock in December 1996 has been given retroactive effect in these financial statements.

Stock Option Plans

The Company's 1992 Incentive Stock Option Plan (the "ISO Plan") terminated on December 16, 1994. Until then, the Company granted incentive stock options to purchase 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 10 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.

Under the Company's 1992 Nonstatutory Stock Option Plan (the "NSO Plan"), non-qualified options to purchase common stock may be granted only to directors and consultants of the Company. Subject to any adjustment as provided by the NSO 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 10 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. The NSO 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 6,250 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 increased from 20,000 shares (post-split) to 15,000 shares per year in 1998 and to 25,000 shares per year in 1999. No options can be granted under the NSO Plan after December 10, 2002.

Under the Company's 1994 Stock Option Plan (the "1994 Plan"), and its 1996 Stock Option Plan (the "1996 Plan"), incentive and nonqualified stock options to purchase Common Stock may be granted to employees and consultants of the Company and its subsidiaries. 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 10 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 the Company's 1999 Stock Option Plan (the "1999 Plan"), nonqualified stock options to purchase Common Stock may be granted to employees and consultants of the Company and its subsidiaries. Subject to any adjustment as provided by the plan, the aggregate number of shares which may be issued and sold may not exceed 3,000,000 shares. The maximum period for exercise of an option may not be more than 10 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 the 1999 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 1999 Plan after March 4, 2009.

The Company 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. No compensation expense has been recognized 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 the Company had accounted for its 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 1999, 1998, the Transition Period and fiscal 1997, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) of 5.88%, 5.20%, 6.45% and 6.74%; dividend yields of 0.0%, 0.0%, 0.9% and 0.9%; volatility factors of the expected market price of the Company's common stock of .82, .96, .67 and .60; 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 the Company's 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.

The Company's pro forma information follows:

	YEARS ENDED DECEMBER 31, 1999	YEARS ENDED DECEMBER 31, 1998	SIX MONTHS ENDED DECEMBER 31, 1997	YEAR ENDED JUNE 30, 1997
	(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)			
Net Income (Loss)				
As reported	$ 33,266	$ (933,854)	$ (31,574)	$(183,377)
Pro forma	24,802	(948,014)	(35,084)	(190,160)
Basic Earnings (Loss) per Share				
As reported	$ 0.17	$ (9.97)	$ (0.45)	$ (2.79)
Pro forma	0.08	(10.12)	(0.50)	(2.89)
Diluted Earnings (Loss) per Share				
As reported	$ 0.16	$ (9.97)	$ (0.45)	$ (2.79)
Pro forma	0.08	(10.12)	(0.50)	(2.89)

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 the Company's 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 the Company's stock option activity and related information follows:

	YEARS ENDED DECEMBER 31, 1999		YEARS ENDED DECEMBER 31, 1998		SIX MONTHS ENDED DECEMBER 31, 1997	
	OPTIONS	WEIGHTED-AVG EXERCISE PRICE	OPTIONS	WEIGHTED-AVG EXERCISE PRICE	OPTIONS	WEIGHTED-AVG EXERCISE PRICE
Outstanding Beginning of Period	11,260,375	$ 1.86	8,330,381	$ 5.49	7,903,659	$ 7.09
Granted	3,210,493	1.11	14,580,063	2.78	3,362,207	8.29
Exercised	(622,120)	0.99	(108,761)	1.35	(219,349)	3.13
Cancelled/Forfeited	(990,319)	1.87	(11,541,308)	5.64	(2,716,136)	13.87
Outstanding End of Period	12,858,429	$ 1.76	11,260,375	$ 1.86	8,330,381	$ 5.49
Exercisable End of Period	5,040,302		3,535,126		3,838,869	
Shares Authorized for Future Grants	2,560,687		1,761,359		4,585,973	
Fair Value of Options Granted During the Period		$ 0.77		$ 2.34		$ 4.98

	YEAR ENDED JUNE 30, 1997 OPTIONS	YEAR ENDED JUNE 30, 1997 WEIGHTED-AVG EXERCISE PRICE
Outstanding Beginning of Year	7,602,884	$ 4.66
Granted	3,564,884	19.35
Exercised	(1,197,998)	1.95
Cancelled/Forfeited	(2,066,111)	22.26
Outstanding End of Year	7,903,659	$ 7.09
Exercisable End of Year	3,323,824	
Shares Authorized for Future Grants	5,212,056	
Fair Value of Options Granted During the Year		$ 7.51

The following table summarizes information about stock options outstanding at December 31, 1999:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING @ 12/31/99	WEIGHTED-AVG. REMAINING CONTRACTUAL LIFE	WEIGHTED-AVG. EXERCISE PRICE	NUMBER EXERCISABLE @ 12/31/99	WEIGHTED-AVG. EXERCISE PRICE
$ 0.08 - $ 0.78	897,982	4.02	$ 0.62	897,982	$ 0.62
$ 0.94 - $ 0.94	2,538,000	9.04	0.94	42,500	0.94

\$ 1.00 - \$ 1.00	31,250	9.01	1.00	31,250	1.00
\$ 1.13 - \$ 1.13	6,679,130	8.68	1.13	1,627,898	1.13
\$ 1.33 - \$ 2.25	1,320,204	4.34	2.00	1,320,204	2.00
\$ 2.38 - \$10.69	1,263,300	6.74	4.75	1,005,405	4.97
\$14.25 - \$14.25	27,000	7.32	14.25	13,500	14.25
\$17.67 - \$17.67	938	0.08	17.67	938	17.67
\$25.88 - \$25.88	625	0.08	25.88	625	25.88
\$30.63 - \$30.63	100,000	6.77	30.63	100,000	30.63
\$ 0.08 - \$30.63	12,858,429	7.77	\$ 1.76	5,040,302	\$ 2.66

The exercise of certain stock options results in state and federal income tax benefits to the Company related to the difference between the market price of the common stock at the date of disposition and the option price. During fiscal 1997, \$4,808,000 was recorded as an adjustment to additional paid-in capital and deferred income taxes with respect to such tax benefits. During 1999, 1998 and the Transition Period, the Company did not recognize any such tax benefits.

10. FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

The Company has only limited involvement with derivative financial instruments, as defined in Statement of Financial Accounting Standards No. 119 "Disclosure About Derivative Financial Instruments and Fair Value of Financial Instruments", and does not use them for trading purposes. The Company's primary objective is to hedge a portion of its exposure to price volatility from producing crude oil and natural gas. These arrangements may expose the Company to credit risk from its counterparties and to basis risk. The Company does not expect that the counterparties will fail to meet their obligations given their high credit ratings.

Hedging Activities

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include:

(i) swap arrangements that establish an index-related price above which the Company pays the counterparty and below which the Company is paid by the counterparty,

(ii) the purchase of index-related puts that provide for a "floor" price below which the counterparty pays the Company the amount by which the price of the commodity is below the contracted floor,

(iii) the sale of index-related calls that provide for a "ceiling" price above which the Company pays the counterparty the amount by which the price of the commodity is above the contracted ceiling, and

(iv) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points.

Results from commodity hedging transactions are reflected in oil and gas sales to the extent related to the Company's oil and gas production. The Company only enters into commodity hedging transactions related to the Company's oil and gas production volumes or CEMI's physical purchase or sale commitments. Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the months of related production.

As of December 31, 1999, the Company had the following open natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1999:

MONTHS	VOLUME (MMBTU)	NYMEX-INDEX STRIKE PRICE (PER MMBTU)
April 2000	600,000	$ 2.50
May 2000	620,000	2.50
June 2000	600,000	2.50
July 2000	620,000	2.50
August 2000	620,000	2.50
September 2000	600,000	2.50
October 2000	620,000	2.50

If the swap arrangements listed above had been settled on December 31, 1999, the Company would have incurred a gain of $0.5 million.

As of December 31, 1999, the Company had no open oil swap arrangements.

The Company has also closed transactions designed to hedge a portion of the Company's domestic oil and natural gas production. The net unrecognized losses resulting from these transactions, $3.9 million as of December 31, 1999, will be recognized as price adjustments in the months of related production. These hedging gains and losses are set forth below ($ in thousands):

MONTH	HEDGING GAINS (LOSSES) GAS	OIL	TOTAL
January 2000	$ --	$ (995)	$ (995)
February 2000	--	(1,061)	(1,061)
March 2000	689	(851)	(162)
April 2000	71	(647)	(576)
May 2000	73	(668)	(595)
June 2000	71	(647)	(576)
July 2000	73	(231)	(158)
August 2000	73	--	73
September 2000	71	--	71
October 2000	73	--	73
	$ 1,194	$(5,100)	$ (3,906)

Subsequent to December 31, 1999, the Company entered into the following natural gas swap arrangements designed to hedge a portion of the Company's domestic gas production for periods after December 1999:

MONTHS	VOLUME (MMBTU)	NYMEX - INDEX STRIKE PRICE (PER MMBTU)
April 2000	8,900,000	$2.593
May 2000	3,410,000	2.737
June 2000	3,300,000	2.737
July 2000	3,410,000	2.741
August 2000	3,410,000	2.741
September 2000	2,100,000	2.696
October 2000	2,170,000	2.696

Subsequent to December 31, 1999, the Company entered into the following crude oil swap arrangements designed to hedge a portion of the Company's domestic crude oil production for periods after December 1999:

MONTHS	MONTHLY VOLUME (BBLS)	NYMEX-INDEX STRIKE PRICE (PER BBL)
March 2000	183,000	$27.512
April 2000	89,000	27.251

In addition to commodity hedging transactions related to the Company's oil and gas production, CEMI periodically enters into various hedging transactions designed to hedge against physical purchase and sale commitments made by CEMI. Gains or losses on these transactions are recorded as adjustments to oil and gas marketing sales in the consolidated statements of operations and are not considered by management to be material.

Interest Rate Risk

The Company also utilizes hedging strategies to manage fixed-interest rate exposure. Through the use of a swap arrangement, the Company believes it can benefit from stable or falling interest rates and reduce its current interest expense. During 1999, the Company's interest rate swap resulted in a $2.0 million reduction of interest expense. The terms of the swap agreement are as follows:

Months	Notional Amount	Fixed Rate	Floating Rate
May 1998 - April 2001	$230,000,000	7%	Average of three-month Swiss Franc LIBOR, Deutsche Mark and Australian Dollar plus 300 basis points
May 2001 - April 2008	$230,000,000	7%	U.S. three-month LIBOR plus 300 basis points

If the floating rate is less than the fixed rate, the counterparty will pay the Company accordingly. If the floating rate exceeds the fixed rate, the Company will pay the counterparty.

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

	DECEMBER 31, 1999							
	YEARS OF MATURITY							
	2000	2001	2002	2003	2004	THEREAFTER	TOTAL	FAIR VALUE
LIABILITIES:	($ IN MILLIONS)							
Long-term debt, including current portion - fixed rate	$ 0.8	$ 0.8	$ 0.6	$ --	$ 150.0	$ 770.0	$ 922.2	$ 838.7
Average interest rate	9.1%	9.1%	9.1%	--	7.9%	9.3%	9.1%	--
Long-term debt - variable rate	$ --	$ 43.5	$ --	$ --	$ --	$ --	$ 43.5	$ 43.5
Average interest rate	--	9.75%	--	--	--	--	9.75%	--

Concentration of Credit Risk

Other financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash, short-term investments in debt instruments and trade receivables. The Company's accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties operated by the Company. The industry concentration has the potential to impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. The Company generally requires letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. The cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

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". The estimated fair value amounts have been determined by the Company 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. The Company estimates the fair value of its long-term (including current maturities), fixed-rate debt using primarily quoted market prices. The Company's carrying amount for such debt at December 31, 1999 and 1998 was $921.4 million and $919.1 million, respectively, compared to approximate fair values of $838.7 million and $654.7 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 Company estimates the fair value of its convertible preferred stock, which was issued in April 1998, using quoted market prices. The Company's carrying amount for such preferred stock at December 31, 1999 and 1998 was $229.8 million and $230.0 million, compared to an approximate fair value of $119.0 million and $48.9 million, respectively.

11. DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

Net Capitalized Costs

Evaluated and unevaluated capitalized costs related to the Company's oil and gas producing activities are summarized as follows:

DECEMBER 31, 1999

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas properties:			
Proved	$ 2,193,492	$ 121,856	$ 2,315,348
Unproved	36,225	3,783	40,008
Total	2,229,717	125,639	2,355,356
Less accumulated depreciation, depletion and amortization	(1,645,185)	(25,357)	(1,670,542)
Net capitalized costs	$ 584,532	$ 100,282	$ 684,814

DECEMBER 31, 1998

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas properties:			
Proved	$ 2,060,076	$ 82,867	$ 2,142,943
Unproved	44,780	7,907	52,687
Total	2,104,856	90,774	2,195,630
Less accumulated depreciation, depletion and amortization	(1,556,284)	(17,998)	(1,574,282)
Net capitalized costs	$ 548,572	$ 72,776	$ 621,348

Unproved properties not subject to amortization at December 31, 1999 and 1998 consisted mainly of lease acquisition costs. The Company capitalized approximately $3.5 million, $6.5 million, $5.1 million and $12.9 million of interest during 1999, 1998, the Transition Period and fiscal 1997, respectively, on significant investments in unproved properties that were not yet included in the amortization base of the full-cost pool. The Company will continue to evaluate its 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	$ 95,329	$ 31,536	$ 126,865
Exploration costs	23,651	42	23,693
Acquisition costs	47,993	4,100	52,093
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, 1998

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Development and leasehold costs	$ 169,491	$ 7,119	$ 176,610
Exploration costs	63,245	5,427	68,672
Acquisition costs	662,104	78,176	740,280
Sales of oil and gas properties	(15,712)	--	(15,712)
Capitalized internal costs	5,262	--	5,262
Total	$ 884,390	$ 90,722	$ 975,112

SIX MONTHS ENDED DECEMBER 31, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Development and leasehold costs	$ 144,283	$ --	$ 144,283
Exploration costs	40,534	--	40,534
Acquisition costs	39,245	--	39,245
Capitalized internal costs	2,435	--	2,435
Total	$ 226,497	$ --	$ 226,497

YEAR ENDED JUNE 30, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Development and leasehold costs	$ 324,989	$ --	$ 324,989
Exploration costs	136,473	--	136,473
Capitalized internal costs	3,905	--	3,905
Total	$ 465,367	$ --	$ 465,367

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

The Company's results of operations from oil and gas producing activities are presented below for 1999, 1998, the Transition Period and fiscal 1997. The following table includes revenues and expenses associated directly with the Company's oil and gas producing activities. It does not include any allocation of the Company's interest costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of the Company's 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) benefit (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, 1998

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas sales	$ 248,909	$ 7,978	$ 256,887
Production expenses	(49,368)	(1,834)	(51,202)
Production taxes	(8,295)	--	(8,295)
Impairment of oil and gas properties	(810,610)	(15,390)	(826,000)
Depletion and depreciation	(143,283)	(3,361)	(146,644)
Imputed income tax (provision) benefit (a)	285,981	5,673	291,654
Results of operations from oil and gas producing activities	$ (476,666)	$ (6,934)	$ (483,600)

SIX MONTHS ENDED DECEMBER 31, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas sales	$ 95,657	$ --	$ 95,657
Production expenses	(7,560)	--	(7,560)
Production taxes	(2,534)	--	(2,534)
Impairment of oil and gas properties	(110,000)	--	(110,000)
Depletion and depreciation	(60,408)	--	(60,408)
Imputed income tax (provision) benefit (a)	31,817	--	31,817
Results of operations from oil and gas producing activities	$ (53,028)	$ --	$ (53,028)

YEAR ENDED JUNE 30, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Oil and gas sales	$ 192,920	$ --	$ 192,920
Production expenses	(11,445)	--	(11,445)
Production taxes	(3,662)	--	(3,662)
Impairment of oil and gas properties	(236,000)	--	(236,000)
Depletion and depreciation	(103,264)	--	(103,264)
Imputed income tax (provision) benefit (a)	60,544	--	60,544
Results of operations from oil and gas producing activities	$ (100,907)	$ --	$ (100,907)

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

Capitalized costs, less accumulated amortization and related deferred income taxes, cannot exceed an amount equal to the sum of the present value (discounted at 10%) 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. At December 31, 1998 and 1997 and June 30, 1997, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues for the Company's proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $826 million, $110 million and $236 million, respectively.

Oil and Gas Reserve Quantities (unaudited)

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

- As of December 31, 1999, Williamson Petroleum Consultants, Inc. ("Williamson"), Ryder Scott Company ("Ryder Scott"), and the Company's internal reservoir engineers evaluated 50%, 16%, and 34% of the Company's combined discounted future net revenues from the Company's estimated proved reserves, respectively.

- As of December 31, 1998, Williamson, Ryder Scott, H.J. Gruy and Associates, Inc. and the Company's internal reservoir engineers evaluated 63%, 12%, 1% and 24% of the Company's combined discounted future net revenues from the Company's estimated proved reserves, respectively.

- As of December 31, 1997, Williamson, Porter Engineering Associates, Netherland, Sewell & Associates, Inc. and internal reservoir engineers evaluated approximately 53%, 42%, 3% and 2% of the Company's combined discounted future net revenues from the Company's estimated proved reserves, respectively.

- As of June 30, 1997, the reserves evaluated by Williamson constituted approximately 41% of the Company's combined discounted future net revenues from the Company's estimated proved reserves, with the remaining reserves being evaluated internally. The reserves evaluated internally in fiscal 1997 were subsequently evaluated by Williamson with a variance of approximately 4% of total proved reserves.

The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise. The Company's 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. As of December 31, 1997 and June 30, 1997, all of the Company's oil and gas reserves were located in the United States.

Presented below is a summary of changes in estimated reserves of the Company for 1999, 1998, the Transition Period and fiscal 1997:

DECEMBER 31, 1999

	U.S.		CANADA		COMBINED	
	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)
Proved reserves, beginning of period ...	22,560	724,018	33	231,773	22,593	955,791
Extensions, discoveries and other additions	4,593	158,801	--	37,835	4,593	196,636
Revisions of previous estimates	3,404	59,904	--	(98,571)	3,404	(38,667)
Production	(4,147)	(96,873)	--	(11,737)	(4,147)	(108,610)
Sale of reserves-in-place	(4,371)	(31,616)	(33)	(796)	(4,404)	(32,412)
Purchase of reserves-in-place	2,756	64,350	--	19,738	2,756	84,088
Proved reserves, end of period	24,795	878,584	--	178,242	24,795	1,056,826
Proved developed reserves:						
Beginning of period	18,003	552,953	33	105,990	18,036	658,943
End of period	17,750	627,120	--	136,203	17,750	763,323

DECEMBER 31, 1998

	U.S.		CANADA		COMBINED	
	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)
Proved reserves, beginning of period ...	18,226	339,118	--	--	18,226	339,118
Extensions, discoveries and other additions	3,448	90,879	--	--	3,448	90,879
Revisions of previous estimates	(4,082)	(60,477)	--	--	(4,082)	(60,477)
Production	(5,975)	(86,681)	(1)	(7,740)	(5,976)	(94,421)
Sale of reserves-in-place	(30)	(3,515)	--	--	(30)	(3,515)
Purchase of reserves-in-place	10,973	444,694	34	239,513	11,007	684,207
Proved reserves, end of period	22,560	724,018	33	231,773	22,593	955,791
Proved developed reserves:						
Beginning of period	10,087	178,082	--	--	10,087	178,082
End of period	18,003	552,953	33	105,990	18,036	658,943

DECEMBER 31, 1997

	U.S.		CANADA		COMBINED	
	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)
Proved reserves, beginning of period ...	17,373	298,766	--	--	17,373	298,766
Extensions, discoveries and other additions	5,573	68,813	--	--	5,573	68,813
Revisions of previous estimates	(3,428)	(24,189)	--	--	(3,428)	(24,189)
Production	(1,857)	(27,327)	--	--	(1,857)	(27,327)
Sale of reserves-in-place	--	--	--	--	--	--
Purchase of reserves-in-place	565	23,055	--	--	565	23,055
Proved reserves, end of period	18,226	339,118	--	--	18,226	339,118
Proved developed reserves:						
Beginning of period	7,324	151,879	--	--	7,324	151,879
End of period	10,087	178,082	--	--	10,087	178,082

JUNE 30, 1997

	U.S.		CANADA		COMBINED	
	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)
Proved reserves, beginning of period ...	12,258	351,224	--	--	12,258	351,224
Extensions, discoveries and other additions	13,874	147,485	--	--	13,874	147,485
Revisions of previous estimates	(5,989)	(137,938)	--	--	(5,989)	(137,938)
Production	(2,770)	(62,005)	--	--	(2,770)	(62,005)
Sale of reserves-in-place	--	--	--	--	--	--
Purchase of reserves-in-place	--	--	--	--	--	--
Proved reserves, end of period	17,373	298,766	--	--	17,373	298,766
Proved developed reserves:						
Beginning of period	3,648	144,721	--	--	3,648	144,721
End of period	7,324	151,879	--	--	7,324	151,879

During 1999, the Company acquired approximately 101 Bcfe of proved reserves through purchases of oil and gas properties for consideration of $52 million. The Company also sold 59 Bcfe of proved reserves for consideration of approximately $46 million. During 1999, the Company recorded upward revisions of 80 Bcfe to the December 31, 1998 estimates of its U.S. reserves, and downward revisions of 99 Bcfe to the December 31, 1998 estimates of its Canadian reserves, for a net Company wide revision of 19 Bcfe, or approximately 1.7%. The upward revisions to its 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 to its Canadian reserves were caused by a reduction of the Company's proved undeveloped locations and an increase in projected transportation and operating costs in Canada, which decreased the economic lives of the underlying properties.

During 1998, the Company acquired approximately 750 Bcfe of proved reserves through mergers or through purchases of oil and gas properties. The total consideration given for the acquisitions was 30.8 million shares of Company common stock, $280 million of cash, the assumption of $205 million of debt, and the incurrence of approximately $20 million of other acquisition related costs. Also during 1998, the Company recorded downward revisions to the December 31, 1997 estimates of approximately 4,082 MBbl and 60,477 MMcf, or approximately 85 Bcfe. These reserve revisions were primarily attributable to lower oil and gas prices at December 31, 1998. The weighted average prices used to value the Company's reserves at December 31, 1998 were $10.48 per barrel of oil and $1.68 per Mcf of gas, as compared to the prices used at December 31, 1997 of $17.62 per barrel of oil and $2.29 per Mcf of gas.

For the six months ended December 31, 1997, the Company recorded downward revisions to the June 30, 1997 reserve estimates of approximately 3,428 MBbl and 24,189 MMcf, or approximately 45 Bcfe. The reserve revisions were primarily attributable to lower than expected results from development drilling and production which eliminated certain previously established proved reserves.

On December 16, 1997, Chesapeake acquired AnSon Production Corporation, a privately owned oil and gas producer based in Oklahoma City. Consideration for this acquisition was approximately $43 million. The Company estimates that it acquired approximately 26.4 Bcfe in connection with this acquisition.

For the fiscal year ended June 30, 1997, the Company recorded downward revisions to the previous year's reserve estimates of approximately 5,989 MBbl and 137,938 MMcf, or approximately 174 Bcfe. The reserve revisions were primarily attributable to the decrease in oil and gas prices between periods, higher drilling and completion costs, and unfavorable developmental drilling and production results during fiscal 1997. Specifically, the Company recorded aggregate downward adjustments to proved reserves of 159 Bcfe for the Knox, Giddings and Louisiana Trend areas.

Standardized Measure of Discounted Future Net Cash Flows (unaudited)

Statement of Financial Accounting Standards No. 69 ("SFAS 69") prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company 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 the Company's 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 the Company's 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, 1998

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Future cash inflows (b)	$ 1,374,280	$ 474,143	$ 1,848,423
Future production costs	(432,876)	(52,493)	(485,369)
Future development costs	(124,717)	(29,634)	(154,351)
Future income tax provision	(6,464)	(143,747)	(150,211)
Net future cash flows	810,223	248,269	1,058,492
Less effect of a 10% discount factor	(303,096)	(132,281)	(435,377)
Standardized measure of discounted future net cash flows	$ 507,127	$ 115,988	$ 623,115
Discounted (at 10%) future net cash flows before income taxes	$ 504,148	$ 156,843	$ 660,991

DECEMBER 31, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Future cash inflows (c)	$ 1,100,807	$ --	$ 1,100,807
Future production costs	(223,030)	--	(223,030)
Future development costs	(158,387)	--	(158,387)
Future income tax provision	(108,027)	--	(108,027)
Net future cash flows	611,363	--	611,363
Less effect of a 10% discount factor	(181,253)	--	(181,253)
Standardized measure of discounted future net cash flows	$ 430,110	$ --	$ 430,110
Discounted (at 10%) future net cash flows before income taxes	$ 466,509	$ --	$ 466,509

JUNE 30, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Future cash inflows (d)	$ 954,839	$ --	$ 954,839
Future production costs	(190,604)	--	(190,604)
Future development costs	(152,281)	--	(152,281)
Future income tax provision	(104,183)	--	(104,183)
Net future cash flows	507,771	--	507,771
Less effect of a 10% discount factor	(92,273)	--	(92,273)
Standardized measure of discounted future net cash flows	$ 415,498	$ --	$ 415,498
Discounted (at 10%) future net cash flows before income taxes	$ 437,386	$ --	$ 437,386

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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 $10.48 per barrel of oil and $1.68 per Mcf of gas.

(c) Calculated using weighted average prices of $17.62 per barrel of oil and $2.29 per Mcf of gas.

(d) Calculated using weighted average prices of $18.38 per barrel of oil and $2.12 per Mcf of gas.

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, 1998

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Standardized measure, beginning of period	$ 430,110	$ --	$ 430,110
Sales of oil and gas produced, net of production costs	(191,246)	(6,144)	(197,390)
Net changes in prices and production costs	(189,817)	--	(189,817)
Extensions and discoveries, net of production and development costs	85,464	--	85,464
Changes in future development costs	72,279	--	72,279
Development costs incurred during the period that reduced future development costs	28,191	--	28,191
Revisions of previous quantity estimates	(64,770)	--	(64,770)
Purchase of reserves-in-place	288,694	164,821	453,515
Sales of reserves-in-place	(3,079)	--	(3,079)
Accretion of discount	46,651	--	46,651
Net change in income taxes	39,377	(40,855)	(1,478)
Changes in production rates and other	(34,727)	(1,834)	(36,561)
Standardized measure, end of period	$ 507,127	$ 115,988	$ 623,115

DECEMBER 31, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Standardized measure, beginning of period	$ 415,498	$ --	$ 415,498
Sales of oil and gas produced, net of production costs	(85,563)	--	(85,563)
Net changes in prices and production costs	26,106	--	26,106
Extensions and discoveries, net of production and development costs	92,597	--	92,597
Changes in future development costs	(7,422)	--	(7,422)
Development costs incurred during the period that reduced future development costs	47,703	--	47,703
Revisions of previous quantity estimates	(62,655)	--	(62,655)
Purchase of reserves-in-place	25,236	--	25,236
Sales of reserves-in-place	--	--	--
Accretion of discount	43,739	--	43,739
Net change in income taxes	(14,510)	--	(14,510)
Changes in production rates and other	(50,619)	--	(50,619)
Standardized measure, end of period	$ 430,110	$ --	$ 430,110

JUNE 30, 1997

	U.S.	CANADA	COMBINED
		($ IN THOUSANDS)	
Standardized measure, beginning of period	$ 461,411	$ --	$ 461,411
Sales of oil and gas produced, net of production costs	(177,813)	--	(177,813)
Net changes in prices and production costs	(99,234)	--	(99,234)
Extensions and discoveries, net of production and development costs	287,068	--	287,068
Changes in future development costs	(12,831)	--	(12,831)
Development costs incurred during the period that reduced future development costs	46,888	--	46,888
Revisions of previous quantity estimates	(199,738)	--	(199,738)
Purchase of reserves-in-place	--	--	--
Sales of reserves-in-place	--	--	--
Accretion of discount	54,702	--	54,702
Net change in income taxes	63,719	--	63,719
Changes in production rates and other	(8,674)	--	(8,674)
Standardized measure, end of period	$ 415,498	$ --	$ 415,498

12. TRANSITION PERIOD COMPARATIVE DATA

The following table presents certain financial information for the twelve months ended December 31, 1998 and 1997, and the six months ended December 31, 1997 and 1996, respectively:

	TWELVE MONTHS ENDED DECEMBER 31, 1998	TWELVE MONTHS ENDED DECEMBER 31, 1997 (UNAUDITED)	SIX MONTHS ENDED DECEMBER 31, 1997	SIX MONTHS ENDED DECEMBER 31, 1996 (UNAUDITED)
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)			
Revenues	$ 377,946	$ 302,804	$ 153,898	$ 120,186
Gross profit (loss)(a)	$ (856,197)	$ (309,041)	$ (93,092)	$ 42,946
Income (loss) before income taxes and extraordinary item	$ (920,520)	$ (251,150)	$ (31,574)	$ 39,246
Income taxes	--	(17,898)	--	14,325
Income (loss) before extraordinary item	(920,520)	(233,252)	(31,574)	24,921
Extraordinary item	(13,334)	(177)	--	(6,443)
Net income (loss)	$ (933,854)	$ (233,429)	$ (31,574)	$ 18,478
Earnings per share - basic				
Income (loss) before extraordinary item	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.40
Extraordinary item	(0.14)	--	--	(0.10)
Net income (loss)	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.30
Earnings per share - assuming dilution				
Income (loss) before extraordinary item	$ (9.83)	$ (3.30)	$ (0.45)	$ 0.38
Extraordinary item	(0.14)	--	--	(0.10)
Net income (loss)	$ (9.97)	$ (3.30)	$ (0.45)	$ 0.28
Weighted average common shares outstanding (in 000's)				
Basic	94,911	70,672	70,835	61,985
Assuming dilution	94,911	70,672	70,835	66,300

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(a) Total revenue less total operating costs.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for 1999 and 1998 are as follows ($ in thousands except per share data):

	QUARTERS ENDED MARCH 31, 1999	JUNE 30, 1999	SEPTEMBER 30, 1999	DECEMBER 31, 1999
Net sales	$ 65,677	$ 80,892	$ 102,140	$ 106,237
Gross profit (loss)(a)	7,067	25,765	36,498	38,190
Net income (loss)	(11,950)	8,147	18,115	18,954
Net income (loss) per share:				
Basic	(0.17)	0.04	0.14	0.15
Diluted	(0.17)	0.04	0.13	0.14

	QUARTERS ENDED MARCH 31, 1998	JUNE 30, 1998	SEPTEMBER 30, 1998	DECEMBER 31, 1998
Net sales	$ 76,765	$ 109,310	$ 106,338	$ 85,533
Gross profit (loss)(a)	(246,036)	(218,645)	13,650	(405,166)
Net income (loss) before extraordinary item	(256,500)	(234,739)	(4,149)	(425,132)
Net income (loss)	(256,500)	(248,073)	(4,149)	(425,132)
Net income (loss) per share before extraordinary item:				
Basic	(3.19)	(2.29)	(0.08)	(4.44)
Diluted	(3.19)	(2.29)	(0.08)	(4.44)

- ----------

(a) Total revenue less total operating costs.

Capitalized costs, less accumulated amortization and related deferred income taxes, cannot 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. At December 31, 1998, June 30, 1998 and March 31, 1998, capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues for the Company's proved reserves, net of related income tax considerations, resulting in writedowns in the carrying value of oil and gas properties of $360 million, $216 million and $250 million, respectively.

During the fourth quarter of 1998, the Company incurred a $55 million impairment charge to adjust certain non-oil and gas producing assets to their estimated fair values. Of this amount, $30 million related to the Company's investment in preferred stock of Gothic Energy Corporation, and the remainder was related to certain of the Company's gas processing and transportation assets located in Louisiana.

14. ACQUISITIONS

During 1998, the Company acquired approximately 750 Bcfe of proved reserves through mergers or through purchases of oil and gas properties. The total consideration given for the acquisitions was $280 million of cash, 30.8 million shares of Company common stock, the assumption of $205 million of debt, and the incurrence of approximately $20 million of other acquisition related costs.

In March 1998, the Company acquired Hugoton Energy Corporation ("Hugoton") pursuant to a merger by issuing 25.8 million shares of the Company's common stock in exchange for 100% of Hugoton's common stock. The acquisition of Hugoton was accounted for using the purchase method as of March 1, 1998, and the results of operations of Hugoton have been included since that date.

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

Pro Forma Information (Unaudited)

	YEARS ENDED DECEMBER 31,	
	1998	1997
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)	
Revenues	$387,638	$379,546
Loss before extraordinary item	(921,969)	(215,350)
Net loss	(935,303)	(215,527)
Loss before extraordinary item per common share	(9.41)	(2.23)
Net loss per common share	(9.55)	(2.23)

The Company acquired other businesses and oil and gas properties during 1999 and 1998. The results of operations of each of these businesses and properties, taken individually, were not material in relation to the Company's consolidated results of operations.

15. SUBSEQUENT EVENTS

In January and February 2000, the Company engaged in five separate transactions with two institutional investors in which the Company exchanged a total of 8.8 million shares of common stock (both newly issued and treasury shares) for 625,000 shares of its issued and outstanding preferred stock with a liquidation value of $31.3 million plus dividends in arrears of $2.9 million. All preferred shares acquired in these transactions were cancelled and retired and will have the status of authorized but unissued shares of undesignated preferred stock.

In connection with a potential restructuring of Gothic Energy Corporation ("Gothic"), Chesapeake and Gothic agreed in March 2000 to substantially revise their joint venture originally entered into in March 1998. In addition, Chesapeake granted Gothic an option to redeem the preferred and common shares of Gothic held by Chesapeake in exchange for rights to certain undeveloped leasehold interests covered by the joint venture agreement. The terms of the agreement are subject to certain conditions, including the approval by certain of Gothic's creditors. Significant terms of the proposed agreement are as follows:

- the joint venture is extended for three years to April 30, 2006,
- Chesapeake is granted a right of first refusal on any property disposition by Gothic,
- Chesapeake becomes operator of 28 wells currently operated by Gothic,
- Chesapeake will have the first right to drill, complete and operate wells in certain areas covered by the joint venture,
- Chesapeake granted Gothic the option to redeem its investment in $50 million liquidation amount of Gothic Series B preferred stock, including dividends in arrears, and 2.4 million shares of Gothic common stock, for a permanent assignment to Chesapeake of certain undeveloped leasehold interests that were originally subject to a reassignment obligation to Gothic.

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	$ --	$(5,731)(a)	$(10,956)	$442,016
December 31, 1998:					
Allowance for doubtful accounts.......	$ 691	$ 1,589	$ 1,000	$ 71	$ 3,209
Valuation allowance for deferred tax assets.............................	$77,934	$380,969	$ --	$ --	$458,903
December 31, 1997:					
Allowance for doubtful accounts.......	$ 387	$ 40	$ 264	$ --	$ 691
Valuation allowance for deferred tax assets.............................	$64,116	$ 13,818	$ --	$ --	$ 77,934
June 30, 1997:					
Allowance for doubtful accounts.......	$ 340	$ 299	$ --	$ 252	$ 387
Valuation allowance for deferred tax assets.............................	$ --	$ 64,116	$ --	$ --	$ 64,116

(a) At December 31, 1998, $5.7 million of the valuation allowance was related to the Company's Canadian deferred tax assets. During 1999, this valuation allowance was eliminated as part of a purchase price reallocation related to a 1998 acquisition.

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2000.

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2000.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2000.

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 the Company pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than April 29, 2000.

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. The Company's consolidated financial statements are included in Item 8 of this report. Reference is made to the accompanying Index to Consolidated Financial Statements.

2. Financial Statement Schedules. Schedule II is included in Item 8 of this report with the Company's consolidated financial statements. No other financial statement schedules are applicable or required.

3. Exhibits. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

EXHIBIT NUMBER		DESCRIPTION
3.1	--	Registrant's Certificate of Incorporation as amended. Incorporated herein by reference to Exhibit 3.1 to Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235).
3.2	--	Registrant's Bylaws. Incorporated herein by reference to Exhibit 3.2 to Registrant's registration statement on Form 8-B (No. 001-13726).
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 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 Amendment No. 1 to Form S-3 registration statement (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.
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 United States Trust Company of New York, As Trustee, with respect to 8.5% Senior Notes due 2012. Incorporated herein by reference to Exhibit 4.1.3 to Registrant 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 Amendment No. 1 to Form S-3 registration statement (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.
4.3	--	Indenture dated as of April 1, 1998 among the Registrant, as Subsidiary Guarantors, and United States Trust Company of New York, As Trustee, with respect to 9.625% Senior Notes due 2005. Incorporated herein by reference to Exhibit 4.3 to Registrant registration statement

on Form S-3 (No. 333-57235). First Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

4.4 -- Indenture dated as of April 1, 1996 among the Registrant, its subsidiaries signatory thereto, as Subsidiary Guarantors, and United States Trust Company of New York, as Trustee, with respect to 9.125% Senior Notes, due 2006. Incorporated herein by reference to Exhibit 4.6 to Registrant's registration statement on Form S-3 (No. 333-1588). First Supplemental Indenture dated December 30, 1996 and Second Supplemental Indenture dated December 17, 1997. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Third Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.3.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

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.

4.11 -- Registration Rights Agreement as of April 22, 1998 among the Registrant and Donaldson, Lufkin & Jenrette Securities Corporation, Morgan Stanley & Co. Incorporated, Bear Stearns & Co. Inc., Lehman Brothers Inc. and J.P. Morgan Securities Inc., with respect to 7% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 4.11 to Registrant's quarterly report on Form 10-Q for the quarter ended March 31, 1998.

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 Registrant's Proxy Statement for its 1996 Annual Meeting of Shareholders and to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.

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.

10.2.1+ -- First Amendment to the Amended and Restated Employment Agreement dated as of December 31, 1998 between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.

10.2.2+ -- First Amendment to the Amended and Restated Employment Agreement dated as of December 31, 1998 between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.

10.2.3+ -- Amended and Restated Employment Agreement dated as of July 1, 1998 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Registrant's annual report on Form 10-K for the year ended December 31, 1998.

10.2.4+	--	Employment Agreement dated as of July 1, 1997 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1997.
10.2.5+	--	Employment Agreement dated as of July 1, 1997 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.5 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.6+	--	Employment Agreement dated as of July 1, 1997 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.6 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.8+	--	Employment Agreement dated as of July 1, 1997 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.9+	--	Amendment to Employment Agreements of Steven C. Dixon, J. Mark Lester, Henry J. Hood and Martha A. Burger dated as of July 1, 1997. Incorporated herein by reference to Exhibit 10.2.9 to Registrant's annual report on Form 10-K for the year ended December 31, 1998.
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).
10.5	--	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*	--	Computation of Ratios
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 Petroleum Engineers
27*	--	Financial Data Schedule

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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, 1999, the Company filed the following Current Reports on Form 8-K:

On November 1, 1999, the Company filed a current report on Form 8-K reporting under Item 5 that the Company issued a press release announcing record earnings and cash flow for the third quarter 1999.

On December 8, 1999, the Company filed a current report on Form 8-K reporting under Item 5 that the Company issued a press release reporting an increase in its Mid-Continent asset base with property acquisition and completion of a significant discovery well.

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 30, 2000

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)	March 30, 2000
/s/ TOM L. WARD Tom L. Ward	President, Chief Operating Officer and Director (Principal Executive Officer)	March 30, 2000
/s/ MARCUS C. ROWLAND Marcus C. Rowland	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 30, 2000
/s/ MICHAEL A. JOHNSON Michael A. Johnson	Senior Vice President - Accounting, Controller and Chief Accounting Officer (Principal Accounting Officer)	March 30, 2000
/s/ EDGAR F. HEIZER, JR. Edgar F. Heizer, Jr.	Director	March 30, 2000
/s/ BREENE M. KERR Breene M. Kerr	Director	March 30, 2000
/s/ SHANNON T. SELF Shannon T. Self	Director	March 30, 2000
/s/ FREDERICK B. WHITTEMORE Frederick B. Whittemore	Director	March 30, 2000
/s/ WALTER C. WILSON Walter C. Wilson	Director	March 30, 2000

INDEX TO EXHIBITS

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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 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 Amendment No. 1 to Form S-3 registration statement (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.
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4.3	--	Indenture dated as of April 1, 1998 among the Registrant, as Subsidiary Guarantors, and United States Trust Company of New York, As Trustee, with respect to 9.625% Senior Notes due 2005. Incorporated herein by reference to Exhibit 4.3 to Registrant registration statement on Form S-3 (No. 333-57235). First Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.
4.4	--	Indenture dated as of April 1, 1996 among the Registrant, its subsidiaries signatory thereto, as Subsidiary Guarantors, and United States Trust Company of New York, as Trustee, with respect to 9.125% Senior Notes, due 2006. Incorporated herein by reference to Exhibit 4.6 to Registrant's registration

statement on Form S-3 (No. 333-1588). First Supplemental Indenture dated December 30, 1996 and Second Supplemental Indenture dated December 17, 1997. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's transition report on Form 10-K for the six months ended December 31, 1997. Third Supplemental Indenture dated April 22, 1998. Incorporated herein by reference to Exhibit 4.4.1 to Registrant's Amendment No. 1 to Form S-3 registration statement (No. 333-57235). Fourth Supplemental Indenture dated July 1, 1998. Incorporated herein by reference to Exhibit 4.3.1 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1998.

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.
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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 Registrant's Proxy Statement for its 1996 Annual Meeting of Shareholders and to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1996.
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.
10.2.1+	--	First Amendment to the Amended and Restated Employment Agreement dated as of December 31, 1998 between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.2.2+	--	First Amendment to the Amended and Restated Employment Agreement dated as of December 31, 1998 between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Registrant's quarterly report on Form 10-Q for the quarter ended June 30, 1999.
10.2.3+	--	Amended and Restated Employment Agreement dated as of July 1, 1998 between Marcus C. Rowland and Chesapeake Energy Corporation.

Incorporated herein by reference to Exhibit 10.2.3 to Registrant's annual report on Form 10-K for the year ended December 31, 1998.

10.2.4+	--	Employment Agreement dated as of July 1, 1997 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Registrant's quarterly report on Form 10-Q for the quarter ended September 30, 1997.
10.2.5+	--	Employment Agreement dated as of July 1, 1997 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.5 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.6+	--	Employment Agreement dated as of July 1, 1997 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.6 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.8+	--	Employment Agreement dated as of July 1, 1997 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.9+	--	Amendment to Employment Agreements of Steven C. Dixon, J. Mark Lester, Henry J. Hood and Martha A. Burger dated as of July 1, 1997. Incorporated herein by reference to Exhibit 10.2.9 to Registrant's annual report on Form 10-K for the year ended December 31, 1998.
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).
10.5	--	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*	--	Computation of Ratios
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 Petroleum Engineers
27*	--	Financial Data Schedule

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* Filed herewith.

+ Management contract or compensatory plan or arrangement.

EXHIBIT 12

	Year Ended June 30, 1997	Six Months Ended Dec 31, 1997	Year Ended Dec 31, 1998	Year Ended Dec 31, 1999
RATIO OF EARNINGS TO FIXED CHARGES				
Income before income taxes and extraordinary item	(180,330)	(31,574)	(920,520)	35,030
Interest	18,550	17,448	68,249	81,052
Preferred Stock Dividends	--	--	12,077	16,711
Bond discount amortization(a)	--	--	--	--
Loan cost amortization	1,455	794	2,516	3,338
Earnings	(160,325)	(13,332)	(837,678)	136,131
Interest expense	18,550	17,448	68,249	81,052
Capitalized interest	12,935	5,087	6,754	3,497
Preferred Stock Dividends	--	--	12,077	16,711
Bond discount amortization(a)	--	--	--	--
Loan cost amortization	1,455	794	2,516	3,338
Fixed Charges	32,940	23,329	89,596	104,598
Ratio	(4.9)	(0.6)	(9.3)	1.3

(A) Bond discount excluded since its included in interest expense

Insufficient coverage	193,265	36,661	927,274	0

EXHIBIT 21

SUBSIDIARIES OF CHESAPEAKE ENERGY CORPORATION
(AN OKLAHOMA CORPORATION)

Corporations	State of Organization
The Ames Company, Inc.	Oklahoma
Arkoma Pittsburg Holding Corporation	Oklahoma
Chesapeake Acquisition Corporation	Oklahoma
Chesapeake Canada Corporation	Alberta, Canada
Chesapeake Energy Louisiana Corporation	Oklahoma
Chesapeake Energy Marketing, Inc.	Oklahoma
Chesapeake Operating, Inc.	Oklahoma
Chesapeake Royalty Company	Oklahoma

Partnerships	
Chesapeake Exploration Limited Partnership	Oklahoma
Chesapeake Louisiana, L.P.	Oklahoma
Chesapeake Panhandle Limited Partnership	Oklahoma

EXHIBIT 23.1

CONSENT OF INDEPENDENT ACCOUNTANTS

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (File Nos. 33-84256, 33-84258, 33-89282, 33-88196, 333-27525, 333-30478, 333-072555 and 333-30324) and Form S-3 (File No. 333-57235) of Chesapeake Energy Corporation of our report dated March 24, 2000 relating to the consolidated financial statements and financial statement schedule, which appears in this Form 10-K.

PRICEWATERHOUSECOOPERS LLP
Oklahoma City, Oklahoma
March 24, 2000

EXHIBIT 23.2

CONSENT OF WILLIAMSON PETROLEUM CONSULTANTS, INC.

As independent oil and gas consultants, Williamson Petroleum Consultants, Inc. hereby consents to (a) the use of our reserve report dated as of December 31, 1999 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 30, 2000 and (b) to the incorporation by reference of this Form 10-K for the year ended December 31, 1999 in the Registration Statements on Form S-8 (Nos. 33-84256, 33-84258, 33-88196, 333-07255, 33-89282, 333-27525, 333-46129, 333-48585, 333-30478 and 333-30324) and on Form S-3 (Nos. 333-50547 and 333-57235).

/s/ WILLIAMSON PETROLEUM CONSULTANTS, INC.

WILLIAMSON PETROLEUM CONSULTANTS, INC.

Midland, Texas
March 30, 2000

EXHIBIT 23.3

CONSENT OF RYDER SCOTT COMPANY PETROLEUM ENGINEERS

As independent oil and gas consultants, Ryder Scott Company Petroleum Engineers hereby consents to (a) the use of our reserve report dated as of December 31, 1999 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 30, 2000 and (b) to the incorporation by reference of this Form 10-K for the year ended December 31, 1999 in the Registration Statements on Form S-8 (Nos. 33-84256, 33-84258, 33-88196, 333-07255, 33-89282, 333-27525, 333-46129, 333-48585, 333-30478, and 333-30324) and on Form S-3 (Nos. 333-50547 and 333-57235).

/s/ RYDER SCOTT COMPANY L.P.

RYDER SCOTT COMPANY L.P.

Houston, Texas
March 30, 2000

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THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM BALANCE SHEET AS OF DECEMBER 31, 1999, AND STATEMENT OF OPERATIONS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 1999, AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH.

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YEAR
DEC-31-1999
JAN-01-1999
DEC-31-1999
38,850
0
54,625
3,218
4,582
97,546
2,423,068
1,703,971
850,533
88,186
964,097
0
229,820
1,059
(448,423)
850,533
354,946
363,508
247,426
328,478
0
9
81,052
35,030
1,764
33,266
0
0
0
33,266
0.17
0.16