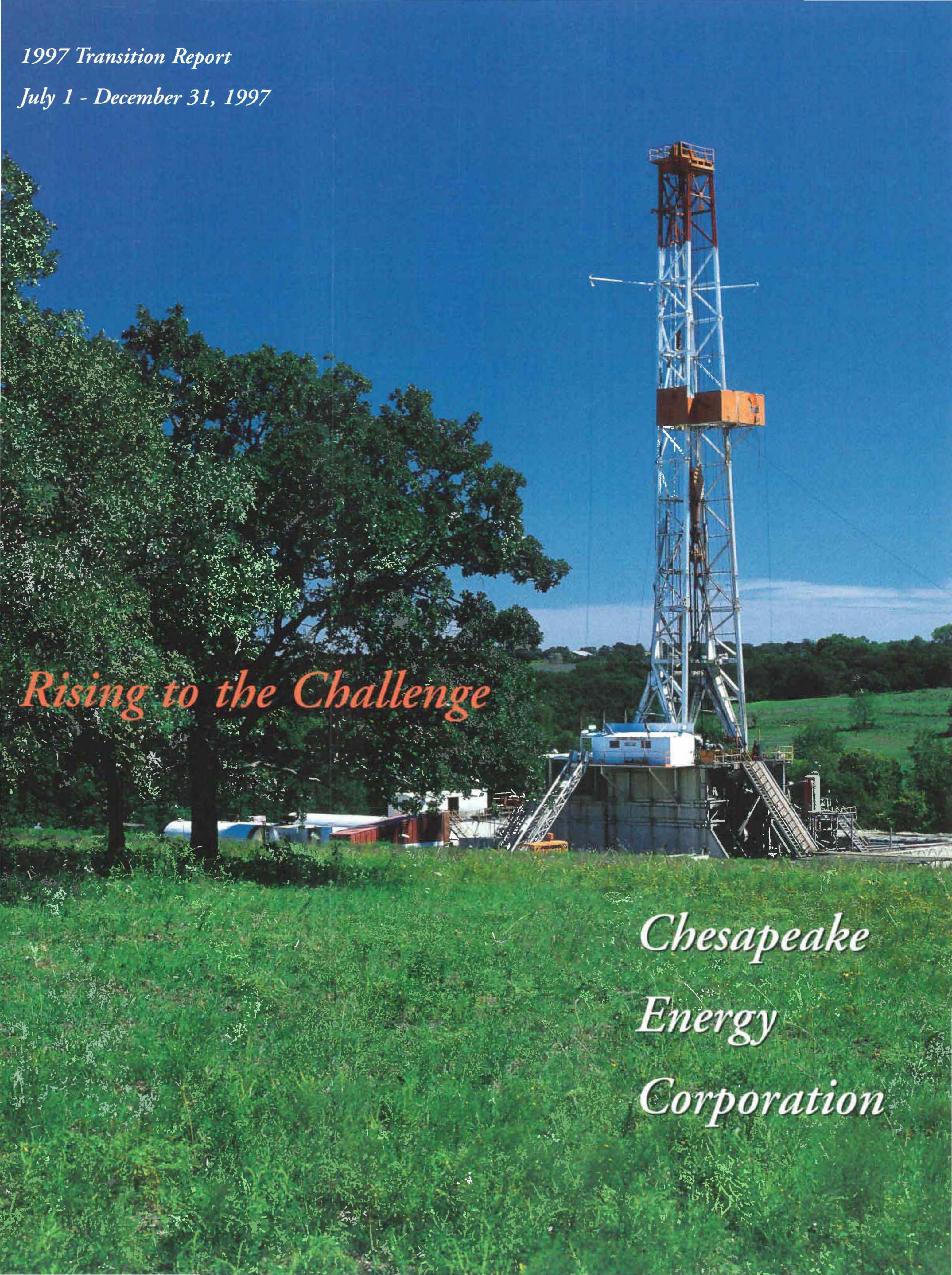
1997 Transition Report

July 1 - December 31, 1997



Rising to the Challenge

Chesapeake Energy Corporation

Selected Financial Data

	Six Months Ended December 31,		Year Ended June 30,				
	1997	1996	1997	1996	1995	1994	1993
Income Data *($ in thousands, except per share data)*							
Oil and gas sales	$ 95,657	$ 90,167	$ 192,920	$ 110,849	$ 56,983	$ 22,404	$ 11,602
Oil and gas marketing sales	58,241	30,019	76,172	28,428	–	–	–
Oil and gas service operations	–	–	–	6,314	8,836	6,439	5,526
Interest and other	78,966	2,516	11,223	3,831	1,524	981	880
Total revenues	232,864	122,702	280,315	149,422	67,343	29,824	18,008
Production expenses and taxes	10,094	5,874	15,107	8,303	4,256	3,647	2,890
Oil and gas marketing expenses	58,227	29,548	75,140	27,452	–	–	–
Service operations	–	–	–	4,895	7,747	5,199	3,653
Impairment of oil and gas properties	110,000	–	236,000	–	–	–	–
Oil and gas depreciation, depletion and amortization	60,408	36,243	103,264	50,899	25,410	8,141	4,184
Other depreciation and amortization	2,414	1,836	3,782	3,157	1,765	1,871	557
General and administrative	5,847	3,739	8,802	4,828	3,578	3,135	4,906
Interest and other	17,448	6,216	18,550	13,679	6,627	2,676	2,282
Total expenses	264,438	83,456	460,645	113,213	49,383	24,669	18,472
Income (loss) before income taxes and extraordinary item	(31,574)	39,246	(180,330)	36,209	17,960	5,155	(464)
Income tax expense (benefit)	–	14,325	(3,573)	12,854	6,299	1,250	(99)
Income (loss) before extraordinary item	$ (31,574)	$ 24,921	(176,757)	23,355	11,661	3,905	(365)
Extraordinary item, net of applicable income tax	–	(6,443)	(6,620)	–	–	–	–
Net income (loss)	$ (31,574)	$ 18,478	$ (183,377)	$ 23,355	$ 11,661	$ 3,905	$ (365)
Earnings (loss) per share	$ (0.45)	$ 0.28	$ (2.79)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
Weighted average shares outstanding	70,835	66,300	65,767	58,342	55,872	48,240	33,552
Property Data *($ in thousands)*							
Oil reserves (MBbls)	18,226	*	17,373	12,258	5,116	4,154	9,622
Gas reserves (MMcf)	339,118	*	298,766	351,224	211,808	117,066	79,763
Reserves in equivalent thousand barrels	74,756	*	67,167	70,795	40,417	23,665	22,915
Reserves in equivalent million cubic feet	448,474	*	403,004	424,775	242,505	141,992	137,495
Future net revenues discounted at 10% (before tax)	$ 466,509	*	$ 437,386	$ 547,016	$ 188,137	$ 141,249	$ 141,665
Oil production (MBbls)	1,857	1,116	2,770	1,413	1,139	537	276
Gas production (MMcf)	27,326	30,095	62,005	51,710	25,114	6,927	2,677
Production in equivalent thousand barrels	6,411	6,132	13,104	10,031	5,325	1,692	722
Production in equivalent million cubic feet	38,468	36,791	78,625	60,190	31,947	10,152	4,333
Average oil price (per Bbl)	$ 18.59	$ 21.88	$ 20.93	$ 17.85	$ 17.36	$ 15.09	$ 20.20
Average gas price (per Mcf)	$ 2.24	$ 2.18	$ 2.18	$ 1.66	$ 1.48	$ 2.06	$ 2.25
Average gas equivalent price (per Mcfe)	$ 2.49	$ 2.45	$ 2.45	$ 1.84	$ 1.78	$ 2.21	$ 2.68

* An independent appraisal of the company's oil and gas reserves was not performed as of December 31, 1996.

Chesapeake Energy Corporation is an independent oil and natural gas producer headquartered in Oklahoma City. The company's operations are focused on exploratory and developmental drilling and producing property and corporate acquisitions in major onshore producing areas of the United States and Canada. The company's internet address is http://www.chesapeake-energy.com.

Rising

to

the

Challenge

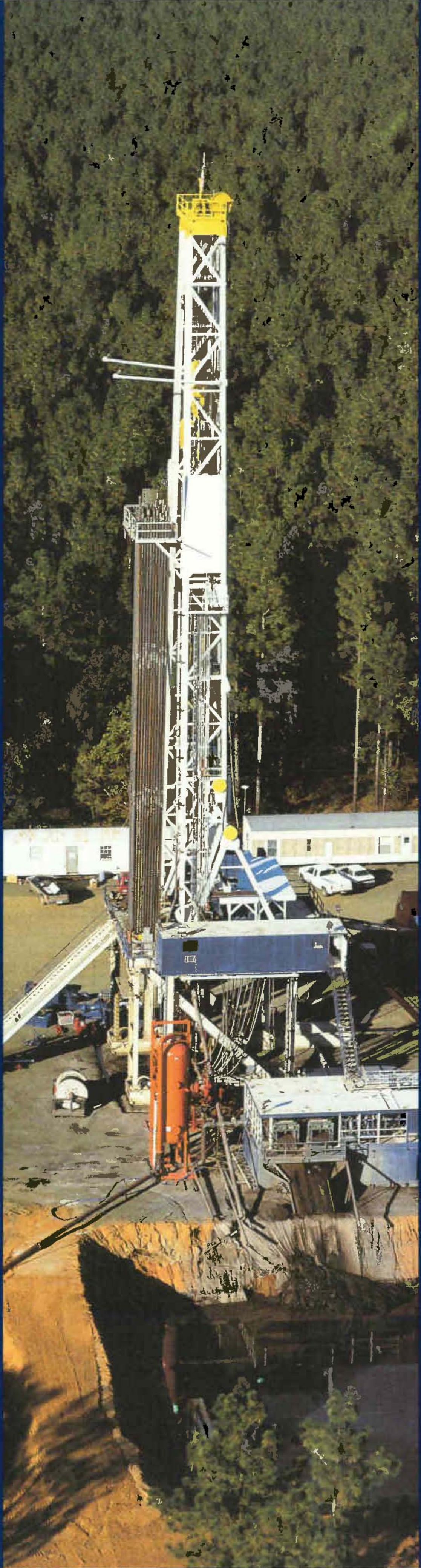
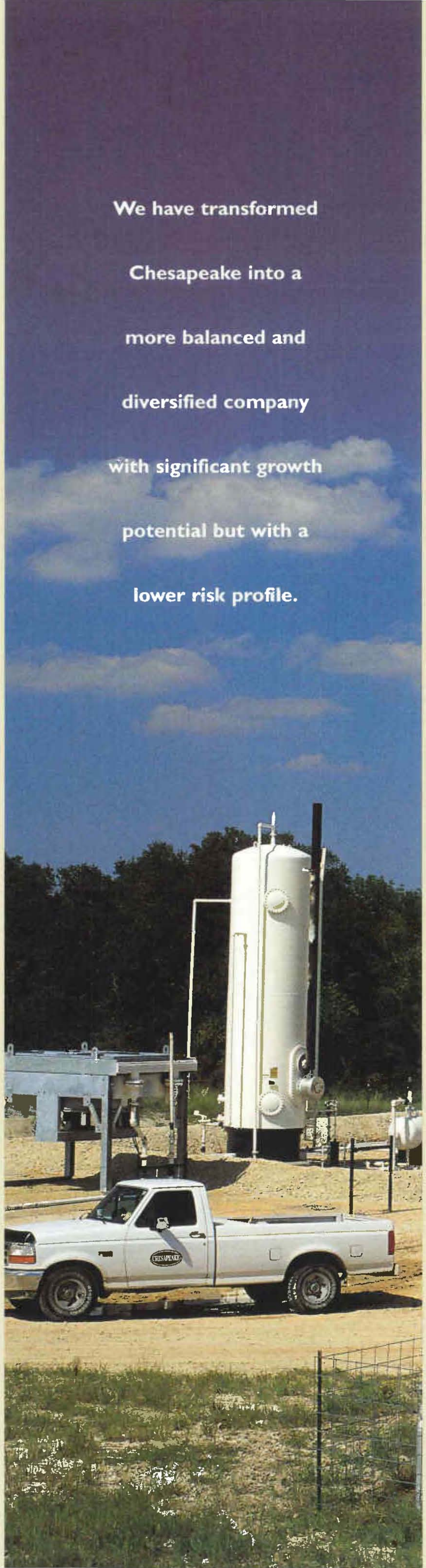


Table of Contents

We have transformed Chesapeake into a more balanced and diversified company with significant growth potential but with a lower risk profile.



Letter to Shareholders

Dear Fellow Shareholders:

Chesapeake's performance in 1997 contrasted sharply with the previous three years when the company led the independent energy sector in production, earnings and cash flow growth and the creation of shareholder value. As owners of approximately 35 million shares of common stock, Chesapeake's management, directors, and employees suffered the greatest impact from the company's disappointing performance in 1997. Determined to prove that 1997 was an aberration, we have taken significant steps over the past several months to improve the company's fortunes in 1998 and beyond. We are pleased to report that our repositioning effort is well underway.

Rising to the Challenge

Chesapeake's growth strategy for 1998 and beyond is designed to enhance shareholder value by creating a stronger, more balanced company. We intend to accomplish our goals by significantly strengthening Chesapeake's reserve base and increasing production levels through the following complementary objectives:

- Acquire and exploit long-lived natural gas assets in the Mid-Continent area;
- Continue developing high cash flow Austin Chalk properties in Texas and Louisiana, but at a significantly reduced pace;
- Develop a substantial Canadian natural gas asset base;
- Deliver high-impact upside through our 3-D seismic exploration programs;
- Act opportunistically as commodity price volatility creates further acquisition and joint venture possibilities.

Mid-Continent Acquisition Program

Before drilling costs rapidly increased in 1997, our strategy of focusing exclusively on growth through the drillbit had the potential to generate the highest growth rates. However, in today's environment of lower oil prices, higher drilling costs and increasing financial and technological pressure on smaller public and private companies, acquisition opportunities provide an excellent complement to our traditional drillbit growth strategy. To capitalize on these opportunities, the company commenced an aggressive acquisition program beginning in late 1997, principally in the Mid-Continent region of the U.S., consisting of Oklahoma, Kansas, and the Texas Panhandle.

The third largest gas basin in the U.S., the Mid-Continent is noted for its long-lived reserves, multiple pay zones, high concentration of natural gas, and attractive exploration upside. It is also an area where Chesapeake has significant geological knowledge, having drilled over 300 producing wells since 1989. Because of these favorable characteristics, Chesapeake has focused the majority of

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its recent acquisitions in the Mid-Continent, where 72% of our estimated 1,138 bcfe of gas reserves are now located. The table below summarizes our acquisition activity during the past seven months:

Transaction Name	Area	Date Announced	Bcfe Acquired	Cost in $MM
AnSon	Mid-Continent	10/97	26	$ 36
DLB*	Mid-Continent	10/97	110	122
Hugoton	Mid-Continent	11/97	246	306
EnerVest	Mid-Continent	1/98	43	38
Ranger	Canada	1/98	54	28
Oxy	Mid-Continent	3/98	109	100
Gothic*	Mid-Continent	3/98	52	20
Sunoma*	Canada	3/98	40	33
Miscellaneous*	Mid-Continent	3/98	36	34
Acquisition Totals			716	$ 717

* Pending acquisitions

The first two acquisitions, announced in October, included the Mid-Continent assets of DLB Oil & Gas, Inc., a publicly traded Oklahoma City company and privately held AnSon Production Corporation. These companies contributed estimated proved oil and gas reserves of 136 bcfe, significant probable and possible reserves, an extensive 3-D seismic database, and profitable gas gathering and marketing operations, at a total cost of $158 million in cash and common stock. The AnSon acquisition was completed in December and the DLB merger is scheduled to close in late April 1998.

Chesapeake's largest acquisition to date, announced last November and closed in March 1998, was Hugoton Energy Corporation. This Wichita, Kansas public company further enhanced Chesapeake's reserve base by adding 246 bcfe of estimated proved reserves in the Mid-Continent, primarily in the prolific Hugoton Gas Field of southwest Kansas and the Anadarko Basin Shelf in northwest Oklahoma. The Hugoton acquisition also contributed additional properties to Chesapeake's Williston Basin producing area in North Dakota and Montana. In the Hugoton transaction, Chesapeake issued 25.8 million shares of common stock and assumed $120 million of outstanding debt.

In January 1998, Chesapeake announced its fourth Mid-Continent asset acquisition with a $38 million, 43 bcfe purchase of the western Oklahoma properties of EnerVest Management Company, L.L.C., a private company headquartered in Houston, Texas. These assets, located near the AnSon properties, added important critical mass to the company's Anadarko Basin core area, the high-potential, prolific gas producing region of western Oklahoma and the Texas Panhandle.

Another acquisition, which complements the Texas Panhandle properties acquired from Hugoton, was the March 1998 $105 million purchase of MC Panhandle Corp., a wholly-owned subsidiary of Occidental Petroleum Corporation. These properties provided 109 bcfe of estimated proved reserves that produce from two shallow formations, the Red Cave at 1,350 feet and the Brown Dolomite at 3,700 feet. Chesapeake believes significant upside potential exists through our planned increased density drilling program for the shallower formations and by utilizing 3-D seismic to identify deeper reserves at depths to 15,000 feet.

The latest example of Chesapeake's opportunistic deal-making strategy is the innovative transaction announced last month with Gothic Energy Corporation, a public company located in Tulsa, Oklahoma. Gothic's assets in the Mid-Continent were largely built through the January 1998 acquisition of most of Amoco's natural gas assets in Oklahoma.

In the Gothic transaction, Chesapeake agreed to acquire 50% of Gothic's 45 bcfe of estimated proved developed natural gas reserves in the Arkoma Basin of eastern Oklahoma for $20 million. Additionally, Chesapeake will invest $50 million in Gothic through a preferred stock offering. As part of the investment, Chesapeake will also acquire 50% of Gothic's 60 bcfe of estimated proved undeveloped reserves in the Arkoma and Anadarko Basins and will enter into a five-year agreement giving Chesapeake the right to participate in Gothic's future drilling and acquisition efforts for a 50% working interest. Chesapeake also will obtain warrants to acquire 15% of Gothic's currently outstanding common stock during the next ten years for $0.01 per share. The Gothic transaction is scheduled to close in late April 1998. We believe this agreement and our 1997 Canadian transactions with Pan East and Ranger Oil, plus our profitable capital investment in Bayard Drilling Technologies, demonstrate management's ability to identify and develop attractive investment opportunities.

Together our Mid-Continent acquisitions have added 620 bcfe of estimated proved reserves (150% of the entire reserves previously owned by the company), increased our natural gas reserves to 81% of total reserves, lengthened our reserve life to 8.5 years, strengthened the proved developed component of our reserve base to 65%, and significantly reduced the risk profile of our company. These acquisitions also increased our backlog of drilling opportunities to approximately 865 potential drillsites, located in prolific natural gas producing areas. Chesapeake continues to evaluate additional Mid-Continent opportunities and believes substantial economic benefits are available to the company from further Mid-Continent consolidation.

We believe investment in the Canadian natural gas industry provides opportunities to explore for high-potential gas reserves and to participate in the anticipated improvement of Canadian gas prices.

Continuing Austin Chalk Development

Chesapeake's second growth objective is to continue developing its Austin Chalk properties in Texas and Louisiana, but at a significantly slower pace than in the past. When drilled successfully, an Austin Chalk well can deliver high levels of production and accelerated cash flows, creating some very attractive rates of return. However, our Louisiana Austin Chalk results outside of the Masters Creek area have not met our expectations and therefore we have materially reduced our Austin Chalk capital expenditure program in 1998 from previous levels.

Pro forma for our Mid-Continent and Canadian acquisitions, the Austin Chalk now accounts for only 18% of our estimated proved reserves and will likely decline to 10-12% in 1999. Our 1998 Austin Chalk drilling will be concentrated in the Masters Creek area in Louisiana and the Independence area in Texas.

Canadian Growth Opportunities

Another objective of our growth strategy is developing a significant Canadian natural gas asset base, on the order of 15-20% of our total estimated proved reserves. We believe investment in the Canadian natural gas industry provides opportunities to explore for high-potential gas reserves in the relatively underdrilled Western

Canadian Sedimentary Basin and to participate in the anticipated improvement of Canadian gas prices associated with new pipeline projects.

Our three recent Canadian investments have provided us with a strategic beachhead in Canada and account for 8% of our pro forma estimated proved reserves. Our first Canadian investment was the acquisition of 19.9% of the common stock of Pan East Petroleum Corp., a publicly-traded oil and gas producer with operations in west central Alberta and northeast British Columbia. In these areas, Pan East and Chesapeake formed a two-year exploration joint venture to more aggressively develop Pan East's asset base.

Our second Canadian alliance is with Ranger Oil Limited, a NYSE-listed Canadian exploration and production independent. In this transaction, Chesapeake invested $48 million to acquire 53 bcfe of estimated proved natural gas reserves and entered into a 40/60 joint venture agreement to further develop the high potential Jean Marie formation in the 3.2 million acre Helmet area of northeast British Columbia. Early results from our 1997 winter drilling program with both Pan East and Ranger look favorable.

In our most recent Canadian transaction, Chesapeake agreed to purchase for $33 million the Helmet area properties of Sunoma Energy Corporation, a privately-held Calgary-based natural gas producer. The properties acquired from Sunoma are located near Ranger's Helmet properties and complement our strategy of concentrating Chesapeake's Canadian gas assets in this high potential area. The company is attracted to the Helmet area because of the estimated three trillion cubic feet of natural gas reserves located in the Jean Marie formation in Helmet. Furthermore, we anticipate this area will be one of the largest beneficiaries of increases in natural gas prices when additional Canadian gas export capacity is completed in late 1998 and in 1999.

Our Canadian investments, which combine Chesapeake's efforts to identify opportunistic reserve additions, develop creative financial structures, and utilize the company's technological expertise are prime examples of the innovative manner in which we plan to deliver additional value to our shareholders.

High-Impact Exploration Upside

Chesapeake's fourth growth objective is to deliver high-impact exploration upside through large and technologically challenging 3-D seismic projects. Later this year, Chesapeake intends to drill a number of 3-D projects conducted during 1997 and early 1998. They include the company's Tuscaloosa Trend project area near Baton Rouge, Louisiana; the Peach Creek prospect in the Wharton County area of southeast Texas; and the continued development of the Strawn formation in the Lovington, New Mexico area.

In the Tuscaloosa Trend, Chesapeake's goal is to emulate the drilling success of the nation's premier Tuscaloosa driller, Amoco Production Company. During the past four years, Amoco successfully completed 17 of 18 Tuscaloosa wells and discovered a reported 400 bcfe through utilization of 3-D seismic.

Chesapeake's two 3-D seismic Tuscaloosa projects cover 90,000 acres in the Morganza and Irene fields, where average estimated reserves using 2-D seismic have averaged 12-15 bcfe per well. Our initial 3-D drilling in both fields should begin by mid-year and the company's geoscientists have generated approximately 25 drillable prospects from these 3-D surveys. We have four Tuscaloosa wells planned in our 1998 drilling program.

We are also enthusiastic about the upside potential of our 30,000 acres of leasehold in the Peach Creek area of Wharton County, Texas. In this area, Chesapeake is engaged in an 85,000 acre 3-D seismic survey with Coastal Corporation, Seagull Energy Corporation, TransTexas Gas Corporation, and Unocal Corporation, focusing on imaging large natural gas traps in the Frio, Yegua, and the especially high-potential Deep Wilcox formation.

Since 1996, Chesapeake has successfully drilled 17 of 21 wells in the Lovington area, located within the Permian Basin in southeast New Mexico. In this area, the company has utilized 3-D seismic to find algal mound buildups estimated to contain an average of 250,000 barrels of oil at an average per well cost of $1 million. In 1998, the company plans to drill 10-15 additional wells and to increase the size of its 3-D coverage.

Future Acquisitions and Joint Venture Opportunities

During the remainder of 1998 and in 1999, Chesapeake will remain alert for complementary Mid-Continent and Western Canadian acquisitions and joint venture opportunities created by commodity price uncertainty, financial or technological limitations experienced by other companies, and the ability to increase ownership in the company's wellbores and fields. As a greater portion of Chesapeake's operations become focused in these two regions, we anticipate that the incremental cost of operating and developing new properties will be reduced through economies of scale.

Management Outlook

Although 1997 was a year of great disappointment for Chesapeake's shareholders and employees, it was also a year of tremendous accomplishment. During 1997, we substantially modified the company's strategy and significantly strengthened and diversified our asset base. Historically, the oil and gas industry has been subject to frequent and sometimes dramatic change. Management of an oil and gas company must be able to quickly modify its strategy to capture the benefits created by industry change and uncertainty. In the past nine months, we have transformed Chesapeake into a more balanced and diversified company with a lower risk profile but with significant growth potential.

Chesapeake is defined today by balance: balance between drillbit growth and acquisitions, balance between Mid-Continent development projects and exploration upside, balance between long and short reserve life properties, and balance between drilling capital expenditures and operating cash flow. We believe the recent completion of our $700 million senior notes and preferred stock offerings are evidence that Chesapeake's turnaround is well underway.

We are hopeful our present and prospective shareholders will appreciate the company's ability to respond quickly and creatively to adversity, rise to the challenges before us and restore Chesapeake as an industry leader in creating shareholder value.

Aubrey K. McClendon

Tom L. Ward

April 20, 1998

Chesapeake is defined today by balance – between drillbit growth and acquisitions, Mid-Continent development projects and exploration upside, long and short reserve life properties, and balance between drilling capital expenditures and operating cash flow.

Board of Directors

Aubrey K. McClendon
Chairman of the Board, Chief Executive Officer and Director

Aubrey K. McClendon has served as Chairman of the Board, Chief Executive Officer and director of the company since its inception in 1989. From 1982 to 1989, Mr. McClendon was an independent producer of oil and gas in affiliation with Tom L. Ward, the company's President and Chief Operating Officer. Mr. McClendon is a member of the Board of Visitors of the Fuqua School of Business at Duke University, an Executive Committee member of the Texas Independent Producers and Royalty Owners Association, a director of the Oklahoma Independent Petroleum Association, and a director of the Louisiana Independent Oil and Gas Association. Mr. McClendon graduated from Duke University in 1981.

Tom L. Ward
President, Chief Operating Officer and Director

Tom L. Ward has served as President, Chief Operating Officer, and a director of the company since its inception in 1989. From 1982 to 1989, Mr. Ward was an independent producer of oil and gas in affiliation with Aubrey K. McClendon. Mr. Ward is a member of the Board of Trustees of Anderson University in Anderson, Indiana. Mr. Ward graduated from the University of Oklahoma in 1981.

E.F. Heizer, Jr.
Director

E. F. Heizer, Jr. has been a director of the company since 1993. From 1985 to the present, Mr. Heizer has been a private venture capitalist. He founded Heizer Corp., a publicly traded business development company, in 1969 and served as Chairman and Chief Executive Officer from 1969 until 1986, when Heizer Corporation was reorganized into a number of public and private companies. Mr. Heizer was Assistant Treasurer of the Allstate Insurance Company from 1962 to 1969 in charge of Allstate's venture capital operations. He was employed by Booz, Allen and Hamilton from 1958 to 1962, Kidder, Peabody & Co. from 1956 to 1958, and Arthur Andersen & Co. from 1954 to 1956. He serves on the advisory board of the Kellogg School of Management at Northwestern University. Mr. Heizer is a director of Material Science Corporation, a New York Stock Exchange listed company in Elk Grove, Illinois and several private companies. Mr. Heizer graduated from Northwestern University in 1951 and from Yale University Law School in 1954.

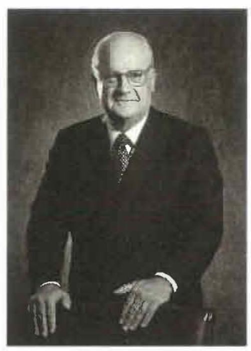
Breene M. Kerr
Director

Breene M. Kerr has been a director of the company since 1993. He is Vice Chairman of Seven Seas Petroleum Corporation, in Houston, Texas, an exploration and production company with operations in Colombia, South America. In 1969, Mr. Kerr founded Kerr Consolidated, Inc. which was sold in 1996. In 1969, Mr. Kerr co-founded the Resource Analysis and Management Group and remained its senior partner until 1982. From 1967 to 1969, he was Vice President of Kerr-McGee Chemical Corporation. From 1951 through 1967, Mr. Kerr worked for Kerr-McGee Corporation as a geologist and land manager. Mr. Kerr has served as chairman of the Investment Committee for the Massachusetts Institute of Technology and is a life member of the Corporation (Board of Trustees) of that university. He served as a director of Kerr-McGee Corporation from 1957 to 1981. Mr. Kerr currently is a trustee and serves on the Investment Committee of the Brookings Institute in Washington, D.C., and has been an associate director since 1987 of Aven Gas & Oil, Inc., an oil and gas property management company located in Oklahoma City. Mr. Kerr graduated from the Massachusetts Institute of Technology in 1951.

Shannon T. Self
Director

Shannon T. Self has been a director of the company since 1993. He is a shareholder of Self, Giddens & Lees, Inc., Attorneys at Law, in Oklahoma City, which he co-founded in 1991. Mr. Self was an associate and shareholder in the law firm of Hastie and Kirschner, Oklahoma City, from 1984 to 1991 and was employed by Arthur Young & Co. from 1979 to 1980. Mr. Self is a Certified Public Accountant. He graduated from the University of Oklahoma in 1979 and from Northwestern University Law School in 1984.

Frederick B. Whittemore
Director



Frederick B. Whittemore has been a director of the company since 1993. Mr. Whittemore has been an advisory director of Morgan Stanley & Co. since 1989 and was a managing director of Morgan Stanley & Co. from 1970 to 1989. He was Vice-Chairman of the American Stock Exchange from 1982 to 1984. Mr. Whittemore is a director of Ecofin Limited, London; Partner Reinsurance Company, Bermuda; Maxcor Financial Group Inc., New York; SunLife of New York, New York; KOS Pharmaceuticals, Inc., Miami, Florida; and Southern Pacific Petroleum, Australia, NL. Mr. Whittemore graduated from Dartmouth College in 1953 and from the Amos Tuck School of Business Administration in 1954.

Walter C. Wilson
Director

Walter C. Wilson has been a director of the company since 1993. From 1963 to 1974 and from 1978 to 1997, Mr. Wilson was a general agent with Massachusetts Mutual Life Insurance Company. From 1974 to 1978, he was Senior Vice President of Massachusetts Mutual Life Insurance Company, and from 1958 to 1963, he was an agent with that company. Mr. Wilson is a member of the Board of Trustees of Springfield College, Springfield, Massachusetts, and is a director of Earth Satellite Corporation of Rockville, Maryland and "Q" Companies, Inc. of Houston, Texas. Mr. Wilson graduated in 1958 from Dartmouth College.

Officers

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

Marcus C. Rowland was appointed Executive Vice President and Chief Financial Officer in March 1998. He served as Senior Vice President and Chief Financial Officer from September 1997 to March 1998 and as Vice President of Finance and Chief Financial Officer of the company from 1993 until 1997. From 1990 until his association with the company, Mr. Rowland was Chief Operating Officer of Anglo-Suisse, L.P. assigned to the White Nights Russian Enterprise, a joint venture of Anglo-Suisse, L.P. and Phibro Energy Corporation, a major foreign operation engaged in oil and gas operations in Russia. Prior to his association with White Nights Russian Enterprise, Mr. Rowland owned and managed his own oil and gas company and prior to that was Chief Financial Officer of a private exploration company in Oklahoma City from 1981 to 1985. Mr. Rowland is a Certified Public Accountant. Mr. Rowland graduated from Wichita State University in 1975.

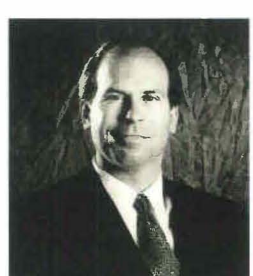
Steven C. Dixon
Sr. Vice President – Operations

Steven C. Dixon has been Senior Vice President – Operations since 1995 and served as Vice President of Exploration from 1991 to 1995. Mr. Dixon was a self-employed geological consultant in Wichita, Kansas, from 1983 through 1990. He was employed by Beren Corporation in Wichita, Kansas, from 1980 to 1983 as a geologist. Mr. Dixon graduated from the University of Kansas in 1980.

J. Mark Lester
Sr. Vice President – Exploration

J. Mark Lester has been Senior Vice President – Exploration since 1995 and served as Vice President – Exploration from 1989 to 1995. From 1986 to 1989, Mr. Lester was employed by Messrs. McClendon and Ward. He was employed by various independent oil companies in Oklahoma City from 1980 to 1986, and was employed by Union Oil Company of California from 1977 to 1980 as a geophysicist. Mr. Lester graduated from Purdue University in 1975 and in 1977.

Henry J. Hood
Sr. Vice President – Land and Legal



Henry J. Hood was appointed Senior Vice President – Land and Legal in 1997 and served as Vice President – Land and Legal from 1995. Mr. Hood was retained as a consultant during the two years prior to his joining the company and was of counsel with the law firm of White, Coffey, Galt & Fite from 1992 to 1995. Mr. Hood was associated with and a Partner of the law firm of Watson & McKenzie from 1987 to 1992. Mr. Hood is a member of the Oklahoma and Texas Bar Associations. Mr. Hood graduated from Duke University in 1982 and from the University of Oklahoma College of Law in 1985.

Ronald A. Lefaive
Sr. Vice President – Accounting, Controller and Chief Accounting Officer

Ronald A. Lefaive has served as Senior Vice President – Accounting, Controller and Chief Accounting Officer since March 1998. From 1993 until March 1998 he served as Controller and Chief Accounting Officer and from 1991 until his association with the company, Mr. Lefaive was Controller for Phibro Energy Production, Inc., an international exploration and production subsidiary of Phibro Energy Corporation. From 1982 to 1991, Mr. Lefaive served as Assistant Controller, General Auditor, and Manager of Management Information Systems at Conquest Exploration Company in Houston, Texas. Prior to joining Conquest, Mr. Lefaive held various financial staff and management positions with the Superior Oil Company from 1980 to 1982 and Shell Oil Company from 1975 to 1982. Mr. Lefaive is a Certified Public Accountant and graduated from the University of Houston in 1975.

Officers

Martha A. Burger
Treasurer and Human Resources Manager

Martha A. Burger has served as Treasurer since 1995 and as Human Resources Manager since 1996. From 1994 to 1995, she served in various accounting positions with the company including Assistant Controller – Operations. From 1989 to 1993, Ms. Burger was employed by Hadson Corporation as Assistant Treasurer and from 1993 to 1994, served as Vice President and Controller of Hadson. Prior to joining Hadson Corporation, Ms. Burger was employed by Phoenix Resource Companies, Inc. as Assistant Treasurer and by Arthur Andersen & Co. Ms. Burger is a Certified Public Accountant and graduated from the University of Central Oklahoma in 1982 and from Oklahoma City University in 1992.

Thomas S. Price, Jr.
Vice President – Corporate Development

Thomas S. Price, Jr. has served as Vice President – Corporate Development since 1992 and was a consultant to the company during the prior two years. He was employed by Kerr-McGee Corporation, Oklahoma City, from 1988 to 1990 and by Flag-Redfern Oil Company from 1984 to 1988. Mr. Price graduated from the University of Central Oklahoma in 1983, from the University of Oklahoma in 1989, and from the American Graduate School of International Management in 1992.

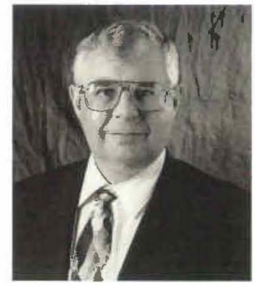
Frank E. Jordan
Vice President – Operations

Frank E. Jordan has served as Vice President – Operations since February 1998. From 1994 to 1998, Mr. Jordan served in various engineering positions with the company, including District Manager – College Station in 1996 and Vice President – Drilling, Northern Division in 1997. Prior to joining Chesapeake, Mr. Jordan served as a Drilling Engineer for Sedco Forex Schlumberger from 1985 to 1989 and as a Production Engineer for Kerr-McGee Corporation from 1991 to 1994. Mr. Jordan is a member of the Society of Petroleum Engineers and graduated from Texas A & M University in 1984 and in 1990.

Stephen W. Miller
Vice President – Drilling

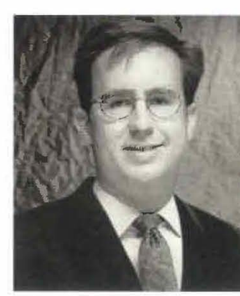
Stephen W. Miller has served as Vice President – Drilling since 1996 and served as District Manager of College Station from 1994 to 1996. Mr. Miller held various engineering positions in the oil and gas industry from 1980 to 1993. Mr. Miller is a registered Professional Engineer in Texas, is a member of the Society of Petroleum Engineers and graduated from Texas A & M University in 1980.

Dale W. Bossert
Vice President – Production



Dale W. Bossert has served as Vice President – Production since 1997. Mr. Bossert was previously employed by Celsius Energy Corporation as Consulting General Manager – Canada in 1996 and by Union Pacific Resources Company of Fort Worth, Texas from 1978 serving in various capacities, including Vice President – Production from 1989 to 1993 and as Vice President – Exploration and Production Services from 1993 to 1995. Mr. Bossert graduated from the University of Alberta in 1966.

Michael A. Johnson
Vice President – Financial Reporting



Michael A. Johnson has served as Vice President – Financial Reporting since March 1998. From 1993 to March 1998 he served as Assistant Controller to the company. From 1991 to 1993, he served as Project Manager for Phibro Energy Production, Inc., an international exploration and production subsidiary of Phibro Energy Corporation. From 1987 to 1991, Mr. Johnson served as audit manager for Arthur Andersen & Co. Mr. Johnson is a Certified Public Accountant and graduated from the University of Texas at Austin in 1987.

Officers

Charles W. Imes
Vice President – Information Technology (Administration)

Charles W. Imes has served as Vice President – Information Technology since 1997 and served as Director – Management Information Systems since 1993. From 1983 to 1993, Mr. Imes owned Imes Software Systems and served as a consultant and supplier of software to the company from 1990 to 1993. Mr. Imes graduated from the University of Oklahoma in 1969.

Terry L. Kite
Vice President – Information Technology (Operations)

Terry L. Kite has served as Vice President – Information Technology since February 1997. From 1981 to 1996, Mr. Kite served in various positions in information technology at Amerada Hess Corporation in Houston, Texas, including Manager – Geoscience and Engineering Systems. Prior to joining Amerada Hess, Mr. Kite held information systems staff positions with Earth Science Programming in Tulsa from 1979 to 1980 and with Seismograph Service Corporation from 1976 to 1979. Mr. Kite graduated from the Colorado School of Mines in 1976.

Stephen L. Douglas
Vice President – Acquisitions

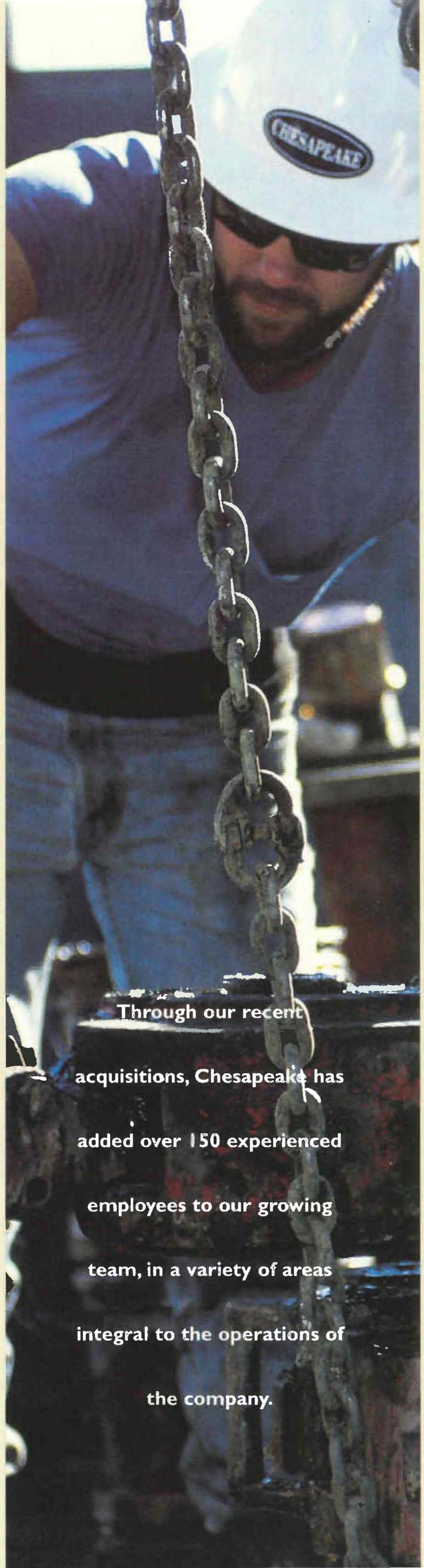
Stephen L. Douglas has served as Vice President – Acquisitions since December 1997. From 1996 until his association with the company, Mr. Douglas was Chief Financial Officer of Peak USA and previously served as Chief Financial Officer of Bechtel Energy Corporation's Russian joint stock company. From 1992 to 1994, Mr. Douglas was Chief Financial Officer for Phibro Energy Production, Inc., an international exploration and production subsidiary of Phibro Energy Corporation. From 1989 to 1991, Mr. Douglas served as a strategic planner and business analyst for FMC, a conglomerate in the oil field equipment manufacturing business. From 1978 until 1988, Mr. Douglas served in various finance and accounting positions with Chevron and Gulf. Mr. Douglas is a Certified Public Accountant and a Certified Management Accountant. He graduated from New England College in 1978 and from Carnegie Mellon University in 1990.

Tony S. Say
President – Chesapeake Energy Marketing, Inc.

Tony S. Say has served as President – Chesapeake Energy Marketing, Inc. since 1995. From 1979 to 1986, Mr. Say was employed by Delhi Gas Pipeline Corporation. From 1986 to 1993, Mr. Say was President and Chief Executive Officer of Clinton Gas Transmission, Inc., a company he co-founded and later sold to a major utility in 1993. In 1993, Mr. Say co-founded Princeton Natural Gas Company which was purchased by Chesapeake Energy Corporation in 1995. Mr. Say is a member of the Natural Gas Society of Oklahoma and the Natural Gas Society of North Texas and graduated from the University of Oklahoma in 1979.

Janice A. Dobbs
Corporate Secretary and Compliance Manager

Janice A. Dobbs has served as Corporate Secretary and Compliance Manager since 1993. From 1975 until her association with the company, Ms. Dobbs was the corporate/securities legal assistant with the law firm of Andrews Davis Legg Bixler Milsten & Price, Inc. in Oklahoma City. From 1973 to 1975, Ms. Dobbs was with Texas International Petroleum Company, an oil and gas exploration and production company in Oklahoma City. Ms. Dobbs is a Certified Legal Assistant, an associate member of the American Bar Association, a member of the American Society of Corporate Secretaries and the Society of Human Resources Management.



Through our recent acquisitions, Chesapeake has added over 150 experienced employees to our growing team, in a variety of areas integral to the operations of the company.

Chesapeake Employees

Joel Alberts
Geologist
Ritchey Albright
Pumper
Christy Allen
Sr. Revenue Analyst
Linda Allen
Legal Assistant
Sam Allen
Landman
Karla Allford
Engineering Technician
Sandy Alvarado
Lease Analysis Supervisor
Ed Alvarez-Salazar
Roustabout
Heather Anderson
Lease Analyst
Mark Anderson
Pumper
Colley Andrews
District Manager-Louisiana
Joe Archuleta
Plant Supervisor
Judy Arias-Sanchez
Accounting Assistant
Paula Asher
Drilling Secretary
Eric Ashmore
Drilling Superintendent
David Ault
Sr. Drilling Engineer
Jack Austin
Geologist
Kelly Baggett
Pumper
Bob Baker
Pumper
Kathyrn Baker-Pfundt
Accounting Assistant
Barbara Bale
Regulatory Analyst
Marilyn Ball
Sr. Accounting Coordinator
Ralph Ball
MIS Support Supervisor
Mary Barker
Production Clerk
Crae Barr
Pumper

Rene Beard
Accounting Coordinator
Francy Beesley
Sr. Lease Analyst
Michaela Benners
Contract Administration Manager
Leonard Berry
Production Superintendent
Rodney Beverly
Production Foreman
Calvin Bodin
Production Facility Operator
Sandra Bogle
Administrative Assistant
Ted Boismier
MIS Network Engineer
Bill Bond
Accountant
Randy Borlaug
Purchasing
Dale Bossert
Vice President-Production
Marion Bowen
Administrative Division Order Analyst
Dick Bradford
Assistant Controller
Susan Bradford
Office Assistant
Steve Brady
Pumper
James Brinkley
Welder
Jim Brock
Sr. Division Order Analyst
Leslie Bross
Land Technician
Joe Brougher
Production Superintendent
Mark Brown
Sr. Lease Analyst
Janice Brown
Lease Technician
Pamela Brown
Sr. Title Analyst
Regina Brown
Accounting Assistant

Rodney Brown
Electrician
Sara Bucy
Accounting Assistant
Martha Burger
Treasurer and Human Resources Director
Karl Burkard
Pumper
Jeff Burling
Geologist
Stephen Burns
Geologist
Shelli Butler
Sr. Accounting Assistant
Sara Caldwell
Title Assistant
Terry Caldwell
Pumper
Michael Cameron
Geologist
Sharon Campbell
Human Resources Assistant
Patti Carlisle
Executive Assistant
Leonardo Carmona
Pusher
Ramon Carmona
Roustabout
Martin Carmona-Cruz
Roustabout
Jamie Carter
Sr. Division Order Analyst
James Castalano
Production Facility Operator
Belinda Cathey
Division Order Assistant
Ilan Cathey
Geology Technician
Kelli Cheek
Office Assistant
Terry Chrispens
Production Technician
Darrell Clark
Production Facility Operator
Dale Clark
Sr. Drilling Engineer
Ivajean Clark
Tax Accountant

Susan Clark
Geology Assistant
Stephen Cody
Geology Technician
Kimberly Coffman
Sr. Accounting Supervisor
Michael Coles
Production Foreman
Gary Collings
Sr. Division Order Analyst
Mike Collis
Production Foreman
Maria Constantino
Accounting Assistant
Kristine Conway
Sr. Accounting Assistant
Dale Cook
Audit Manager
Walter Cook
Production Foreman
Randy Cornelsen
Pumper
Frank Coshow
Production Foreman
Stacey Costa
Drilling Technician
Rose-Marie Coulter
Lease Technician
Marie Cox
Accounting Assistant
Jeff Crawford
MIS Supervisor
Tiffany Cruce
Production Assistant
Michelle Cullen
Division Order Technician
Elaine Darby
Operations Technician
Ken Davidson
District Manager-Oklahoma
Ted Davis
Pumper
Jason Davis
Production Facility Operator
Kevin Decker
Production Coordinator
Robin Delgado
Office Assistant

Casidy Denney
Administrative Assistant
George Denny
Landman
Tim Denny
Administrative Services Coordinator
David DeSalvo
Production Foreman
Alton Dickey
Pumper
Lynn Diel
Division Order Assistant
Bruce Dixon
Production Foreman
Steve Dixon
Sr. Vice President-Operations
Janice Dobbs
Corporate Secretary and Compliance Manager
Barbara Dodson
Assistant Geologist
Justin Dodson
Roustabout
Kim Doty
Lease Analyst
Stephen Douglas
Vice President-Acquisitions
Sandy Doyle
Contract Administrator
Coni Dreyer
Division Order Analyst
Greg Drwenski
Production Engineer
Mandy Duane
Land Technician
Michael Dubea
Production Facility Operator
Gary Dunlap
Land Manager-Louisiana
Don Dunn
Pumper
Laurie Eck
Accounting Coordinator
Heidi Einspahr
Sr. Accountant

Chesapeake Employees

Steve Emick
Pumper

Kyle Essmiller
Financial Accounting Supervisor

Jan Fair
Operations Assistant

Amy Fell
Production Technician

David Ferguson
Landman

Lisa Finley
Gas Controller

Gary Finn
Pumper

Tammy Flaming
Receptionist

Traci Folks
Accounting Assistant

Amy Foreman
Receptionist

Pat Foster
Geology Technician

Rick Foster
Geology Technician

Barbara Frailey
Land Assistant

Joy Franklin
Production Assistant

Billy Free
District Foreman

Sherry Freeman
Sr. Accounting Assistant

Dennis Frick
Production Foreman

Dale Gann
Vice President-Anson Gas Marketing

Linda Gardner
Executive Assistant

Terry Garrison
Pumper

Steve Gaskins
Pumper

Stacy Gilbert
Office Assistant

Robert Gilkes
Gas Revenue Sr. Accountant

Kim Ginter
Division Order Assistant

Debbie Glasgow
Administrative Assistant

Katrina Glennie
Office Assistant

Charlene Glover
Landman

Robin Glynn
Drilling Engineer

Janie Go
Sr. Accounting Assistant

Randy Goben
Assistant Controller

Ron Goff
Sr. Drilling Engineer

Jim Gomez
Graphics Lease Analyst

Traci Gonzales
Tax Manager

Pat Goode
Land Manager-Northern Mid-Continent

Dana Gordon
Land Technician

Marty Gore
Land Technician

Tony Gore
Accountant

Chris Gottschalk
Production Foreman

Jimmy Gowens
Kansas Geology Manager

Ranae Green
Accounting Assistant

Jennifer Grigsby
Assistant Treasurer

Mark Grommesh
Kansas Seismic Manager

Brian Gross
Production Engineer

Melissa Gruenewald
Sr. Gas Accountant

Brian Guire
MIS Programmer

James Gulde
Production Facility Operator

Cheryl Hamilton
Accountant

Shane Hamilton
Administrative Services

Cliff Hanoch
Geophysicist

Jeff Hanson
Oil Revenue Coordinator

Kathy Harrell
Sr. Land Technician

Jeff Harris
Contract Administrator

Joey Harris
Production Foreman

Gayle Harris
Division Order Supervisor

Gaylon Havel
Field Representative

Jimmy Hayes
Pumper

Garve Hays
MIS Technical Support Supervisor

Julie Hays
Lease Analyst

Mike Hazlip
Landman

Duane Heckelsberg
Geologist

Robert Hefner, IV
Geologist

Shawnda Heimerman
Accountant

Steve Henley
Production Superintendent

Larry Hesse
Pumper

David Higgins
Production Foreman

Kristi Hitz
Production Assistant

JoAnna Ho
Accounts Payable Coordinator

Carol Holden
Division Order Supervisor

Jay Holt
Pumper

Larry Holladay
Drilling Superintendent

Henry Hood
Sr. Vice President-Land and Legal

Marilyn Hooser
Sr. Title Analyst

Ken Hopkins
Production Facility Operator

Greg Horn
Pumper

Michael Horn
Associate Geophysicist

Jan Horton
Landman

Charles Houston
Pumper

Steve Howe
Reservoir Engineer

Carol Hudson
Accountant

Chris Hudson
Land Technician

Pam Huggins
Engineering Assistant

Eric Hughes
Roustabout

Fred Hughes
Graphics Lease Analyst

Jean Hughes
Production Technician

Richard Hughes
Production Foreman

Richard Huxman
Pumper

Brian Imes
Administrative Services

Charles Imes
Vice President-Information Technology

Kim Imes
Vendor Contract Coordinator

Lavonda Isaacs
Land Technician

Lorrie Jacobs
Human Resources Administrator

Eugene James
Pumper

Christa Jantz
Land Assistant

Brad Johnson
Pumper

Doug Johnson
Geologist

Jim Johnson
Vice President-Chesapeake Energy Marketing, Inc.

Mike Johnson
Vice President-Financial Reporting

Rusty Johnson
Roustabout

Lee Johnston
Production Foreman

Mike Johnston
Pumper

David Jones
Auditor

Frank Jordan
Vice President-Operations

Thomas Kaney
Pumper

Susan Keller
Engineering Assistant

Taylor Kemp
Administrative Services

Phyllis Kimray
Land Technician

Gene Kincheloe
JIB Supervisor

Michalle King
Office Manager and Human Resources Representative

Terry Kite
Vice President-Information Technology

Thomas Kizzar
Pumper

Mack Knapp
Production Facility Operator

Darvin Knapp
Lead Drilling Superintendent

Dana Knaub
Pumper

Greg Knight
Engineering Technician

Mark Kohutek
Pumper

Marvin Kramer
Pumper

Ted Krigbaum
Landman

Wes Kruckenberg
Production Foreman

Sandi Lagaly
Oil Revenue Coordinator

Steve Lane
Geologist

Chesapeake Employees

Gwen Lang
Administrative Assistant
Jesse Langford
Landman
Barry Langham
Production Engineer
Richard Lariscy
Roustabout
Kim Laughlin
Administrative Assistant
Cindy LeBlanc
Land Assistant
Mike Lebsack
Graphics Lease Analyst
Dan LeDonne
Administrative Services Supervisor
Chris Lee
Assistant Engineer
Ron Lefaive
Sr. Vice President - Accounting, Controller and Chief Accounting Officer
Vanessa Leon
Geological Technician
Steven Lepretre
Production Facility Operator
Mark Lester
Sr. Vice President-Exploration
Charles Long
Production Facility Operator
Kimberly Louthan
Lease Analyst
Kinney Louthan
Landman
Heath Lovinggood
Gas Revenue Coordinator
Janet Lowrey
Administrative Division Order Analyst
Barry Lucas
Pumper
Michael Ludlow
Pumper
Sarah Lumen
Sr. Lease Analyst
Larry Lunardi
Geophysicist

Jan Lyons
Accounting Assistant
Troy Mahan
Pumper
Felipe Maldonado
Pusher
Liz Mallett
Executive Assistant
John Marks
PC Applications Programmer
Tim Marnich
Lead Production Facility Operator
Ben Mathis
Drilling Engineer
Sandy Mathis
Executive Assistant
Allen May
Pumper
Beverley McBride
Gas Marketing Analyst
Sam McCaskill
Drilling Superintendent
Rich McClanahan
Production Engineer
Aubrey McClendon
Chairman of the Board and Chief Executive Officer
Joe McClendon
Special Projects
Carrol McCoy
Sr. Lease Analyst
Frank McGee
Roustabout
Dallas McMurphy
Pumper
Janelle McNeely
Title Supervisor
Sondra McNeiland
Executive Assistant
Carl McSpadden
Accounts Payable Manager
Dorina Meihls
Accounting Assistant
Ricky Mercer
Production Facility Operator
Claudia Miller
Accounting Assistant
Steve Miller
Vice President-Drilling
Darren Minks
Accountant

Laura Minter
Lease Records Assistant
Linda Mollman
Land Technician
Tommy Morphew
Pumper
Jennifer Morris
Accounting Assistant
Don Morrison
RPG Programmer
Ernie Morrison
Geologist
James Morton
Pumper
Reba Moser
Gas Revenue Manager
Eric Murray
Production Facility Operator
Leland Murray
Pumper
Liz Muskrat
Title Analyst
Tara Nash
Lease Technician
Bob Neely
MIS User Support
Ira Neff
Production Foreman
Dennis Neill
Production Facility Operator
Mickey Nemecek
Lease Payments Supervisor
Allen Nichols
Production Engineer
Samantha Nicholson
Accounting Assistant
Linda Noss
Revenue Analyst
Buddy Novak
Drilling Engineer
Mary Jane Nunley
Division Order Analyst
John O'Quinn
Production Facility Operator
Gerda Oliver
Cashier
Ray Osborn
Pumper
Ed Oursler
Dispatcher
Lisa Owens
Gas Controller

Carol Passick
Sr. Programmer
Amy Patel
G & A Accountant
Gary Payne
Pumper
Greg Pearce
Field Representative
Michelle Peery
Payroll Administrator
Robert Perkins
Production Foreman
Ursula Perry
Receptionist
Linda Peterburs
Accountant
Dale Petty
Accounting Coordinator
Ty Phoenix
Pumper
Randy Pierce
Purchasing Manager
Marion Poindexter
Sr. Lease Analyst
Pat Pope
Sr. Accounting Coordinator
Robert Pope
Geologist
Erick Porter
Lease Records Administrator
Bobby Portillo
Pusher
Fernando Portillo
Pumper
Debbie Poteete
Accounting Assistant
Robert Potts
Geology Technician
Robert Powell
Assistant Production Foreman
Shannon Presley
Production Facility Operator
Heather Preston
Sr. Lease Analyst
Ron Prewitt
Geophysicist
Tom Price, Jr.
Vice President-Corporate Development
Carlin Price
Sr. Title Analyst

Wayne Psencik
District Manager-Texas
Thomas Putz
Roustabout
John Qualls
Pumper
Lori Ray
Sr. Land Technician
Jerry Reeve
Accountant
Bob Reeves
Assistant Controller
Deborah Reichert
Gas Revenue Sr. Accountant
Aaron Reyna
Reservoir Engineer
Glen Reynolds
Pumper
Jackie Rhoads
Office Administrator
Jo Rhone
Lease Administrator
Matt Richards
Gas Marketing Representative
Deborah Richardson
Executive Assistant
Mark Richeson
Production Engineer
Christie Rickey
Accounting Assistant
Earl Ringeisen
Kansas District Manager
Mark Robins
Joint Interest Audit Coordinator
Carole Robinson
Tax Accountant
Steve Robinson
Pumper
Les Rodman
Landman
Randy Rodriguez
Field Representative
Lawrence Rogers
Production Foreman
Pat Rolla
Geological Manager
Janna Rothwell
Operations Accounting Coordinator
Ray Roush
Attorney

Chesapeake Employees

Marc Rowland
Executive Vice President and Chief Financial Officer
Teddy Rowland
Production Foreman
Bob Rowley
Pumper
Kelly Ruminer
Volume Contract Administrator
Craig Ruff
Production Superintendent
Kenneth Rupp
Pumper
Beth Russ
G & A Accountant
Danny Rutledge
Production Foreman
Bryan Sagebiel
MIS Network Supervisor
Terry Sample
Pumper
Marlene Sanders
Contract Analyst
Tony Say
President-Chesapeake Energy Marketing, Inc.
John Schartz
Pumper
Hank Scheel
Assistant Controller
Patti Schlegel
Land Systems Coordinator
Charles Scholz
Pumper
Bonnie Schomp
Landman
Kurt Schrantz
Geophysicist
Delores Schreiber
Account Coordinator
Jolene Schur
Administrative Division Order Analyst
Kurt Schweigert
Landman
Cathy Scola
Production Assistant
Ricky Scruggs
Pumper
Cheryl Self
Land Technician

David Sellers
Pumper
Stephanie Shedden
Lease Analyst
Ellen Short
Administrative Assistant
Kurt Shults
Production Superintendent
Arlene Shuman
Sr. Lease Analyst
Carolyn Simmons
Division Order Assistant
Maria Sinclair
Land Assistant
Dianne Slaughter
Production Assistant
April Smith
Gas Revenue Accountant
Charles Smith
Attorney
Todd Smith
Administrative Services
Jason Smith
Production Facility Operator
Sheri Smith
Sr. Accounting Assistant
Vivian Smith
Executive Assistant
Wilma Smith
Division Order Analyst
Jan Solinski
Sr. Division Order Analyst
Kevin Soter
Production Engineer
Antonio Soto
Roustabout
George Soto
Pumper
Deborah Sparks
Accounting Assistant
David Squire
Accounting Coordinator
Krysta Starkey
Treasury Analyst
Larry Stephens
Field Geologist
Donna Stewart
Accounting Assistant

Stan Stinnett
Pumper
Brenda Stremble
Title Analyst
John Striplin
Field Representative
Randy Summers
Production Superintendent
Trudy Sutton
Accounting Assistant
Wes Tayrien
Pumper
Randy Thomas
Sr. Acquisition Accounting Supervisor
Rebecca Thomas
Production Assistant
Terri Thomas
JIB Analyst
Jennifer Thompson
Contract Analyst
Mike Thompson
Pumper
Rachel Thompson
Sr. Accountant
Bill Torry
Gas Marketing Operations Manager
Lynda Townsend
Landman
John Tracy
Pumper
Ken Turner
Drilling Superintendent
Jimmie Turnpaugh
Pumper
Guy Unger
Roustabout
Frank Unsicker
Financial Applications Supervisor
Jerome Urban
Pumper
Arlene Valliquette
Regulatory Technician
Amy VanBrunt
Accounts Payable Supervisor
Joe Vaughan
Right of Way Coordinator/ Landman
Melissa Verett
Tax Accounting Coordinator

Peggy Vosika
Sr. Lease Analyst
Brent Voto
Operations Accountant
Michelle Waddell
Volume Control Analyst
Bill Wagner
Sr. Division Order Analyst
James Walck
Pumper
Allen Waldroup
Pumper
Ronnie Walker
Production Facility Operator
Ronnie Ward
Land Manager-Southern Mid-Continent
Tom Ward
President and Chief Operating Officer
Kimberly Wares
Accountant
Julie Washam
Investor Relations
Patsy Watters
Sr. Division Order Analyst
Clarence Watts
Production Foreman
Melanie Weaver
Sr. Title Analyst
Susan Weaver
Accounting Assistant
Keith Weekly
Production Facility Operator
Janet Weeks
Engineering Technician
Lance Weihs
Lease Technician
Greg Weinschenk
Pumper
Lu Ann Wernli
Safety Administrator
Norma Wheaton
Revenue Analyst
Amanda Whipple
Office Assistant
Dennis Whipple
Pumper
Colene Whitaker
Sr. Land Technician

Craig White
Technical Systems Coordinator
Shelly White
Title Analyst
Anthony Wildman
Pumper
Angela Wiley-Lair
Land Technician
Ken Will
Drilling Superintendent
Cindi Williams
Engineering Technician
Don Williams
Accounting Analyst
Jeff Williams
Landman
Thomas Williams
Drilling Engineer
Curtis Williford
Pumper
Durell Willoughby
MIS Systems Administrator
Wendy Wilson
Production Assistant
Brian Winter
Geologist
David Wittman
Production Superintendent
Julie Wolf
Accounts Payable Supervisor
Jimmy Wright
Production Foreman
Nancy Wyskup
Landman
Alan Zeiler
MIS User Support
Gerald Zgabay
Production Foreman
Keith Zimmerman
Pumper

Glossary of Terms

Algal Mound. A type of bioherm formed from the buildup of algae deposits.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet of natural gas equivalent.

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

Commingled Well. A well producing from two or more formations through common well casing and a single tubing string.

DD&A. Depreciation, depletion, and amortization.

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.

Downdip Wells. Wells producing from deeper depths lower on a structure than updip wells.

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.

Finding Costs. The capital costs associated with finding and developing oil and gas reserves.

Formation. An identifiable single geologic horizon.

Fracture stimulation. Action taken to increase the inherent productivity of a prospective formation through the hydraulic injection of water, diesel, or CO2 at high pressures and high rates.

Full-cost Ceiling Test Writedown. A non-cash charge to earnings as mandated by the Securities and Exchange Commission for companies utilizing the full-cost method of accounting. Under the full-cost method of accounting, all costs of acquisition, exploration and development of oil and gas reserves are capitalized into a "full-cost pool" as incurred and properties in the pool are depleted and charged to operations using the unit-of-production method based on the ratio of current production to total proved oil and gas reserves. To the extent that such capitalized costs (net of accumulated depreciation, depletion, and amortization) less deferred taxes exceed the present value of estimated future net cash flows from proved oil and gas reserves and the lower of cost or fair value of unproved properties after income tax effects, such earnings but would not have an impact on cash flows from operating activities. Once incurred, a writedown of oil and gas properties is not reversible at a later date, even if oil and gas prices subsequently increase.

G&A Expenses. General and administrative expenses.

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.

Increased Density. A well drilled in addition to the number of wells permitted under normal spacing regulations to accelerate recovery or prevent loss of reserves.

Independent Producer. A nonintegrated producer of oil and gas with no refining or retail marketing operations.

Lease Operating Expenses. The costs of maintaining and operating property and equipment on a producing oil and gas lease.

MBbls. One thousand barrels of oil.

Mcf. One thousand cubic feet of natural gas.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent; a unit of measurement which combines oil, natural gas liquids, and natural gas. Oil and natural gas liquids are converted to natural gas based upon their relative energy content at the rate of 6 mcf for each barrel of oil or natural gas liquids.

Operating Costs. The sum of lease operating costs, production taxes, G&A expenses, and oil and gas depreciation, depletion, and amortization.

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

Payzone. The producing formation(s) of a well.

Present Value. When used with respect to oil and gas reserves, present value is 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 natural gas or that is capable of production.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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 ftiture 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 a known reservoir(s) on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Reserve Life. The term in years required to deplete the company's proved oil and gas reserve base at current production rates.

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.

3-D Seismic. Advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

Tcf. One trillion cubic feet of natural gas.

Tcfe. One trillion cubic feet of natural 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.

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☐ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

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

For the Transition Period from July 1, 1997 to December 31, 1997
Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.01	New York Stock Exchange
9.125% Senior Notes due 2006	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 ☑ 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 25, 1998 was $452,116,000. At such date, there were 100,102,000 shares of Common Stock issued and outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

PORTIONS OF THE REGISTRANT'S DEFINITIVE PROXY STATEMENT FOR THE 1998 ANNUAL MEETING OF SHAREHOLDERS ARE INCORPORATED BY REFERENCE IN PART III

PART I

ITEM 1. BUSINESS

Overview

Chesapeake Energy Corporation ("Chesapeake" or the "Company") is an independent oil and gas company engaged in the exploration, production, development and acquisition of oil and natural gas in major onshore producing areas of the United States and Canada.

The Company has changed its fiscal year end from June 30 to December 31. This Transition Report on Form 10-K relates to the six months ended December 31, 1997 (the "Transition Period").

From inception in 1989 through December 31, 1997, Chesapeake drilled and participated in a total of 824 gross (334 net) wells, of which 768 gross (312 net) wells were completed. From June 30, 1990 to December 31, 1997, the Company's estimated proved reserves increased to 448 Bcfe from 11 Bcfe and total assets increased to $953 million from $8 million. Despite this overall favorable record of growth, in fiscal 1997 and in the Transition Period, the Company incurred net losses of $183 million and $32 million, respectively, primarily as a result of $236 million and $110 million, respectively, impairments of its oil and gas properties. The impairments were the amounts by which the Company's capitalized costs of oil and gas properties exceeded the estimated present value of future net revenues from its proved reserves at June 30, 1997 and at December 31, 1997, respectively. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations — Impairment of Oil and Gas Properties".

In response to the losses, Chesapeake significantly revised its business strategy during the Transition Period. These revisions included (i) reducing the size and risk of its exploratory drilling program, especially in the Louisiana Trend, (ii) acquiring significant quantities of long-lived natural gas reserves, particularly in the Mid-Continent region of the U.S., (iii) building a larger inventory of lower risk drilling opportunities through acquisitions and joint ventures and (iv) reducing its capital expenditure budget for exploration and development to more closely match anticipated cash flow from operations.

The Company has acquired or has agreed to acquire a substantial amount of proved oil and gas reserves through mergers and acquisitions of oil and gas properties. Since October 1997, the Company has entered into 10 transactions to acquire approximately 716 Bcfe of estimated proved reserves (the "Acquisitions") at an estimated cost of $717 million. Of these transactions, one was closed in December 1997, three were closed in the first quarter of 1998 and six are pending. These transactions are discussed in more detail under "Recent and Pending Acquisitions."

Reference is made to the "Glossary" that appears at the end of this Item 1 for definitions of certain terms used in this Form 10-K.

Description of Business

Since its inception in 1989 through mid-1997, Chesapeake's primary business strategy was growth through the drillbit. Using this strategy, the Company rapidly expanded its reserves and production through an aggressive drilling program. However, in mid-1997 the Company's drilling disappointments in Louisiana and the industry's escalating drilling and completion costs caused management to change the Company's business strategy. The Company is now focused on acquiring proved developed reserves, primarily in the Mid-Continent Region of the United States and in Western Canada, and increasing its portfolio of low to moderate risk drilling opportunities.

Management believes that attractive opportunities exist to consolidate assets onshore in the U.S., particularly in the Mid-Continent Region. This area is characterized by long-life natural gas reserves that typically have multiple producing formations. Management believes that consolidation of reserves in this area will add significant value through greater operating efficiencies and the application of horizontal drilling and 3-D seismic to previously underdeveloped properties. In addition, long-life natural gas reserves provide a solid foundation for higher-risk exploration activities and provide the opportunity to benefit from potentially higher natural gas prices in the future. The Company has made substantial progress in building a long-life reserve base by acquiring or agreeing to acquire approximately 716 Bcfe of proved reserves for an estimated $717 million since October 1997.

In pursuing its revised strategy, the Company has better positioned itself to pursue opportunities that provide the highest risk-adjusted returns, either through the drillbit or acquisitions. Further, the Company believes its substantial drilling expertise and strong exploration staff will allow it to more fully exploit acquired assets. Finally, the long-lived nature of the assets acquired allows the Company greater capital investment flexibility in times of low commodity prices without experiencing a significant decline in production.

The following table sets forth the Company's estimated proved reserves (net of interests of other working and royalty interest owners and others entitled to share in production), the related present value (discounted at 10%) of the proved reserves, and the estimated capital expenditures required to develop the Company's proved undeveloped reserves at December 31, 1997, and does not include approximately 690 Bcfe of proven reserves acquired or to be acquired after December 31, 1997.

Areas	Oil (MBbl)	Gas (MMcf)	Gas Equivalent (MMcfe)	Percent of Proved Reserves	Present Value (Disc. @ 10%) ($ in 000's)	Estimated Capex To Develop PUD's ($ in 000's)
Mid-Continent Region	5,832	184,313	219,305	49%	$186,732	$ 64,626
Austin Chalk Trend	8,694	138,362	190,526	43	233,601	74,351
Other areas	3,700	16,443	38,643	8	46,176	13,944
Total	18,226	339,118	448,474	100%	$466,509	$152,921

Primary Operating Areas

The Company's strategy is to focus its acquisition and drilling efforts in three areas: (i) the Mid-Continent Region (consisting of Oklahoma, southwestern Kansas and the Texas Panhandle), (ii) the Austin Chalk Trend in Texas and Louisiana, and (iii) the western Canadian provinces of Alberta and British Columbia. In addition, the Company will selectively pursue exploration projects such as the Tuscaloosa Trend in Louisiana, the Deep Wilcox project in Wharton County, Texas, and the Lovington project in New Mexico.

Mid-Continent Region. The Company's Mid-Continent Region assets represented 49% of the Company's total proved reserves as of December 31, 1997. The Company has entered into seven transactions involving the acquisition of Mid-Continent properties during the past six months. Of these acquisitions, only the AnSon acquisition was included in the Company's December 31, 1997 proved reserves. Set forth below is a table which summarizes the Company's announced Mid-Continent transactions:

Seller	Date Announced	Status	Primary Area of Operation	Estimated Proved Reserves as of December 31, 1997 (in Bcfe)	Estimated Proved Reserves Acquisition Cost (in millions)
AnSon Production Corporation	October 1997	Closed December 1997	Deep Anadarko Basin	26	$ 36(1)
DLB Oil and Gas, Inc.	October 1997	Pending; scheduled to close April 1998	Southern and Northwestern Oklahoma	110	$122(1)
Hugoton Energy Corporation	November 1997	Closed March 1998	Southwestern Kansas, Northwestern Oklahoma, Texas Panhandle	246	$306(1)
EnerVest Management Company, L.L.C.	January 1998	Closed February 1998	Deep Anadarko Basin	43	$ 38
MC Panhandle Corp. (a wholly-owned subsidiary of Occidental Petroleum Corporation)	March 1998	Pending; scheduled to close May 1998	Texas Panhandle	108	$100(1)
Gothic Energy Corporation	March 1998	Pending; scheduled to close April 1998	Arkoma and Anadarko Basins	52(2)	$ 20
Miscellaneous (two transactions)	March 1998	Pending; scheduled to close May 1998	Arkoma and Anadarko Basins	35	$ 34
			Totals	620 Bcfe	$656

(1) Excludes other assets of $7 million for AnSon, $10 million for DLB, $20 million for Hugoton and $5 million for MC Panhandle. Also excludes estimated transaction fees and expenses.

(2) Includes an estimated 30 Bcfe of proved undeveloped reserves associated with a 50% interest in a five-year drilling and acquisitions participation agreement.

Pro forma for the Acquisitions, the Company's proved reserves as of December 31, 1997 were approximately 1,138 Bcfe, of which 811 Bcfe, or 71%, are located in the Mid-Continent.

In the Transition Period, the Company invested approximately $67 million to drill 18 gross (11.8 net) wells in the Mid-Continent. The Company has budgeted approximately $88 million for the Mid-Continent during 1998, representing approximately 38% of the Company's total budget for exploration and development activities during the year. The Company anticipates the Mid-Continent will contribute approximately 63 Bcfe of production, pro forma for the Acquisitions, during 1998, or 47% of expected total production.

Austin Chalk Trend. Chesapeake's second largest concentration of reserves and its highest concentration of present value (as of December 31, 1997 and before giving effect to the Acquisitions) is located in the Austin Chalk Trend, which consists of the Giddings Field in Texas and the central portion of Louisiana and far southeast Texas (the "Louisiana Trend"). The Company's activities in the Louisiana Trend are concentrated in the Masters Creek area of central Louisiana.

The Company initiated its exploration and development efforts in the Giddings Field in 1992 and peak activity occurred in 1994 and 1995. From 1992 through December 31, 1997, the Company drilled 226 wells in this area with a 97% success rate. During the Transition Period, the Giddings Field contributed approximately 16.6 Bcfe, or 43% of the Company's total production. The Company expects production to decline in this relatively mature area in 1998. In the Transition Period, the Company invested approximately $13 million to drill 11 gross (4.2 net) wells in Giddings. The Company has budgeted approximately $12 million to drill 8 gross (3.9 net) wells in Giddings during 1998.

In late 1994, Occidental Petroleum Corporation ("Occidental") drilled a significant horizontal Austin Chalk discovery well in the Masters Creek area. Chesapeake responded to Occidental's announcement by extensively reviewing and analyzing vertical drilling reports, electric logs, mud logs, seismic data and production records to arrive at a geological conclusion that the Austin Chalk could be productive across a large portion of central and southeastern Louisiana. Accordingly, and in competition with Union Pacific Resources Company, Sonat, Inc., Occidental, Amoco Production Company, and others, Chesapeake invested approximately $149 million from fiscal 1995 through December 31, 1997 to acquire over 1.1 million acres of leasehold in the Louisiana Trend. Beginning in 1995 and continuing through December 31, 1997, Chesapeake expended an additional $215 million to initiate drilling efforts on 80 gross (37.9 net) exploratory and developmental wells to evaluate its leasehold position.

From December 1996 through April 1997, the Company initiated drilling efforts on 15 of its exploratory wells in the Louisiana Trend. Between April 1997 and July 1997, the Company completed operations on 10 of these wells, eight of which were completed after June 1, 1997. Based upon the disappointing results from these wells, the Company made the determination that a significant amount of leasehold previously classified as unevaluated had become evaluated. This determination resulted in a transfer of approximately $91 million of previously unevaluated leasehold costs to the Company's full cost pool. Combined with disappointing drilling results, higher drilling costs and lower oil and gas prices, the Company incurred a $236 million full-cost ceiling writedown in the fourth quarter of fiscal 1997.

At June 30, 1997, the Company had nine rigs operating in the Louisiana Trend. As a result of the disappointing results being encountered at that time, the Company began to reduce its exploration and development activities in Louisiana, and by March 20, 1998 the Company was operating six rigs in the Louisiana Trend.

During the Transition Period, the Company completed operations on 11 wells in the Masters Creek area. Although 10 of the 11 wells were commercially productive, the $58 million of drilling costs incurred were higher and developed oil and gas reserves were lower than expected. The lower reserve quantities were due in part to lower oil prices at December 31, 1997. The Company incurred approximately $85 million in capital expenditures in the Louisiana Trend during the Transition Period and transferred approximately $11 million of leasehold costs from all areas of the Louisiana Trend to the amortization base of its full-cost pool.

The Company intends to focus its Louisiana drilling in 1998 in the Masters Creek area and to allow others to lead the exploration of areas outside of Masters Creek. For 1998, the Company has budgeted $64 million to drill approximately 13 gross (10.7 net) wells targeting the Austin Chalk formation in the Louisiana Trend. This expenditure, in combination with anticipated seismic costs, represents approximately 27% of the Company's planned exploration and development capital expenditures for 1998. Although it has substantially reduced its budget for the Louisiana Trend, the Company believes there are significant economic drilling opportunities remaining in the Masters Creek area. Additionally, the Company is now completing the various 3-D seismic programs necessary to begin evaluating its Louisiana leasehold for potential Tuscaloosa exploration opportunities.

Western Canada Region. During fiscal 1996 and 1997, the Company began to evaluate the possibility of developing a third core area of operations in western Canada. Management believes the North American gas market is significantly tightening and as a result, Canadian natural gas prices, which have significantly lagged U.S. natural gas prices during the past 15 years, should increase markedly in the next 12 months. Management also believes the exploration potential of western Canada exceeds the upside potential of most onshore areas in the U.S. The Company has recently entered into three transactions which have established a substantial presence in western Canada and expects to increase its natural gas assets in western Canada in 1998. A summary of the Company's Canadian transactions to date are summarized below:

Seller	Date Announced	Status	Primary Area of Operation	Estimated Proved Reserves as of December 31, 1997 (in Bcfe)	Estimated Proved Reserves Acquisition Cost (in millions)
Pan East Petroleum Corp.	November 1997	Closed December 1997	Western Alberta, Northeastern British Columbia	None; purchased 19.9% of Pan East's common stock and entered into a two year, 50/50 drilling and acquisitions participation agreement	N/A
Ranger Oil Limited	January 1998	Closed January 1998	Northeastern British Columbia	54	$ 28(1)
Sunoma Energy Corporation	March 1998	Pending; scheduled to close April 1998	Northeastern British Columbia	42	$ 33
			Totals	96 Bcfe	$ 61

(1) Excludes $20 million related to unevaluated leasehold and other assets.

Other Operating Areas

Tuscaloosa Trend. In 1997 Chesapeake initiated two large 3-D seismic projects to evaluate approximately 90,000 acres of leasehold in the Tuscaloosa Trend portion of Louisiana. The Tuscaloosa is one of the most prolific deep gas reservoirs located along the Gulf Coast and 3-D seismic has proven effective in reducing the risk associated with the exploration for deep gas reserves in the Tuscaloosa. The Company anticipates initiating its drilling program for the Tuscaloosa formation during 1998 and has budgeted $25 million to drill 4 wells.

Permian Basin. In 1995 the Company initiated drilling activity in the Permian Basin in the Lovington area of Lea County, New Mexico. In this project, the Company is utilizing 3-D seismic technology to search for algal reef buildups that management believes have been overlooked in this portion of the Permian Basin because of inconclusive results provided by traditional 2-D seismic technology. During the Transition Period, the Company initiated 10 wells in the Lovington area, six of which were successfully completed, one was unsuccessful and three were drilling. The Company has budgeted approximately $17 million to drill 15 gross (10.0 net) wells and conduct seismic in this area during 1998.

Wharton County, Texas. During fiscal 1997, the Company acquired approximately 25,000 net acres at a cost of approximately $29 million in Wharton County, Texas. This exploration project is seeking gas production from the shallower Frio and Yegua sands and from the Deep Wilcox at depths of up to 19,000 feet. The Company intends to participate with a 55% interest in an 85,000 acre 3-D seismic program with Coastal Oil & Gas Corporation, Seagull Energy Corporation and other industry partners during 1998 to delineate potential future drillsites in the vicinity of Coastal's Zeidman Trustee wells.

Williston Basin. During fiscal 1996, Chesapeake began acquiring leasehold in the Williston Basin, located in eastern Montana and western North Dakota, and as of December 31, 1997 owned approximately 1.0 million gross (0.6 million net) acres. During the Transition Period, the Company drilled and successfully completed six wells targeting the Red River formation on the northern portion of its leasehold. The Company has budgeted $2 million to drill 2 gross (1.4 net) wells during 1998 in the Williston Basin.

Recent and Pending Acquisitions

In October 1997, Chesapeake agreed to acquire by merger the Mid-Continent operations of DLB Oil & Gas, Inc. ("DLB"). In its Mid-Continent division, DLB owns approximately 110 Bcfe of proved reserves, nine gas gathering systems and a gas marketing subsidiary. Chesapeake will pay $17.5 million in cash and will issue five million shares of Chesapeake common stock as merger consideration to the shareholders of DLB and will assume approximately $85 million in debt at closing. The closing of the DLB acquisition, which is expected to occur in late April 1998, is subject to approval by DLB shareholders and other customary conditions. Certain shareholders of DLB, who collectively own approximately 78% of outstanding DLB common stock, have granted Chesapeake an irrevocable proxy to vote such shares in favor of the merger.

In November 1997, Chesapeake agreed to acquire Hugoton Energy Corporation, which was closed on March 10, 1998. Each share of Hugoton common stock was converted into the right to receive 1.3 shares of Chesapeake common stock, resulting in the issuance of approximately 25.8 million shares of Chesapeake common stock. Excluding transaction fees, this transaction was valued at approximately $326 million, including the assumption of $120 million in bank debt at closing. Hugoton owns approximately 246 Bcfe of proved reserves in addition to its portfolio of undeveloped mineral interests, gas gathering systems, probable and possible reserves and other corporate assets.

In December 1997, Chesapeake purchased from Pan East Petroleum Corp. ("Pan East"), a publicly-traded Canadian exploration and production company, 19.9% of Pan East's common stock for $22 million. The purpose of Chesapeake's investment was to assist Pan East in financing its share of the exploration, development and acquisition activities under a joint venture whereby Chesapeake has the right to participate as a non-operator with up to a 50% interest in all drilling activities and acquisitions made by Pan East during the two years ending December 31, 1999.

In December 1997, Chesapeake acquired AnSon Production Corporation ("AnSon"), a privately owned oil and gas producer that owned estimated proved reserves of 26 Bcfe, substantial undeveloped mineral interests, and a gas marketing subsidiary. Consideration for the AnSon acquisition was approximately $43 million, consisting of 3,792,724 shares of Chesapeake common stock and cash consideration remaining to be paid in accordance with the terms of the merger agreement.

In January 1998, Chesapeake entered into 40/60 alliance with Ranger Oil Limited ("Ranger") to jointly develop a 3.2 million acre area of mutual interest in the Helmet area of northeastern British Columbia. As part of the transaction, Chesapeake paid Ranger approximately $48 million to acquire 54 Bcfe of estimated proved reserves (100% natural gas), 160,000 net acres of leasehold, and 40% of Ranger's infrastructure in the area.

In February 1998, Chesapeake purchased the Mid-Continent properties of privately owned EnerVest Management Company, L.L.C. for $38 million. The primarily undeveloped properties are located in the Anadarko Basin of Oklahoma, are 90% natural gas and consist of 43 Bcfe of estimated proved reserves.

In March 1998, Chesapeake agreed to acquire all of the stock of MC Panhandle Corp., a wholly owned subsidiary of Occidental. Chesapeake has agreed to pay $105 million in cash for estimated proved reserves of approximately 108 Bcfe in the West Panhandle Field in Carson, Gray, Hutchinson and Moore Counties of the Texas Panhandle. The reserves are 100% natural gas, have an estimated reserve-to-production index of eight years, and are 85% proved developed producing. During 1997, the wells produced approximately 13 Bcf (36 MMcf of natural gas per day) net to Occidental's interest from 256 wells, of which all but two were operated by Occidental. Chesapeake will assume operations of the acquired wells and will own an average working interest and net revenue interest of 99.5% and 85.2%, respectively. The effective date of the transaction is January 1, 1998 with closing scheduled for late May 1998.

In March 1998, Chesapeake agreed to acquire the British Columbia properties of Sunoma Energy Corporation for $33 million. Virtually all of the 42 Bcfe of estimated reserves to be acquired are associated with wells operated by Ranger in the Helmet area. The properties are 98% natural gas, have an estimated reserves-to-production index of 10 years. The transaction has an effective date of January 1, 1998, and is scheduled to close in late April 1998.

In March 1998, Chesapeake agreed to acquire from Gothic Energy Corporation an estimated 22 Bcfe of proved natural gas reserves in the Arkoma Basin of Oklahoma for $20 million. Additionally, in conjunction with Chesapeake's agreement to purchase $50 million of Gothic's 12% preferred stock (with ten-year warrants to purchase 15% of Gothic's currently outstanding common stock for $0.01 per share), Chesapeake entered into a five year drilling and acquisitions participation agreement with Gothic. As part of the transactions, Gothic transferred to Chesapeake approximately 30 Bcfe of proved undeveloped reserves. The transaction has an effective date of January 1, 1998, and is scheduled to close in late April 1998.

In March 1998, Chesapeake agreed to acquire approximately 35 Bcfe of estimated proved reserves in the Mid-Continent Region from two parties for $34 million. The properties are 85% natural gas and have an estimated reserves-to-production index of 10 years. The transactions have an effective date of January 1, 1998, and are scheduled to close in May 1998.

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.

	Six Months Ended December 31, 1997		Year Ended June 30,					
			1997		1996		1995	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development:								
Productive	55	24.4	90	55.0	111	49.5	133	42.6
Non-productive	1	.3	2	.2	4	1.6	5	2.8
Total	56	24.7	92	55.2	115	51.1	138	45.4
Exploratory:								
Productive	28	15.5	71	46.1	29	16.5	11	5.3
Non-productive	2	0.9	8	5.7	4	1.4	1	.7
Total	30	16.4	79	51.8	33	17.9	12	6.0

At December 31, 1997, the Company was drilling 13 gross (10.1 net) wells, of which one gross (one net) well has been successfully completed and 11 gross (9.1 net) wells are still being drilled or tested. The Company was also participating with minority interests in 19 non-operated wells being drilled at that date.

Well Data

At December 31, 1997, the Company had interests in approximately 1,113 (401.0 net) producing wells, of which 152 (68.6 net) were classified as primarily oil producing wells and 961 (332.4 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:

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
NET PRODUCTION:				
Oil (MBbl)	1,857	2,770	1,413	1,139
Gas (MMcf)	27,326	62,005	51,710	25,114
Gas equivalent (MMcfe)	38,468	78,625	60,190	31,947
OIL AND GAS SALES ($ IN 000's):				
Oil	$34,523	$ 57,974	$ 25,224	$19,784
Gas	61,134	134,946	85,625	37,199
Total oil and gas sales	$95,657	$192,920	$110,849	$56,983
AVERAGE SALES PRICE:				
Oil ($ per Bbl)	$ 18.59	$ 20.93	$ 17.85	$ 17.36
Gas ($ per Mcf)	$ 2.24	$ 2.18	$ 1.66	$ 1.48
Gas equivalent ($ per Mcfe)	$ 2.49	$ 2.45	$ 1.84	$ 1.78
OIL AND GAS COSTS ($ PER Mcfe):				
Production expenses and taxes	$ .27	$ .19	$ .14	$ .13
General and administrative	$ .15	$ .11	$ .08	$ .11
Depreciation, depletion and amortization of oil and gas properties	$ 1.57	$ 1.31	$ .85	$ .80

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:

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ In thousands)		
Development costs	$120,628	$187,736	$138,188	$ 78,679
Exploration costs	40,534	136,473	39,410	14,129
Acquisition costs:				
Unproved properties	25,516	140,348	138,188	24,437
Proved properties	39,245	—	24,560	—
Capitalized internal costs	2,435	3,905	1,699	586
Proceeds from sale of leasehold, equipment and other	(1,861)	(3,095)	(6,167)	(11,953)
Total	$226,497	$465,367	$335,878	$105,878

Acreage

The following table sets forth as of December 31, 1997 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 Region	234	75	328	143	562	218
Austin Chalk Trend	183	109	1,576	1,188	1,759	1,297
Other areas	81	52	1,609	1,005	1,690	1,057
Total	498	236	3,513	2,336	4,011	2,572

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. By the terms of these 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 the Transition Period, the following three customers individually accounted for 10% or more of the Company's total oil and gas sales:

	Amount	Percent of Oil and Gas Sales
	($ In thousands)	
Aquila Southwest Pipeline Corporation	$20,138	21%
Koch Oil Company	18,594	19
GPM Gas Corporation	12,610	13

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

Chesapeake Energy Marketing, Inc. ("CEMI") and AnSon Gas Marketing ("AGM") both wholly-owned subsidiaries, provide 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 the 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. These strategies include (1) 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, (2) 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, (3) 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 (4) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points. Results from 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 hedging transactions related to the Company's oil and gas production volumes or CEMI and AGM physical purchase or sale commitments.

As of December 31, 1997, the Company had the following oil swap arrangements for periods after December 1997:

Months	Volume (BBls)	NYMEX-Index Strike Price (Per Bbl)
January through June 1998	724,000	$19.82

After year-end 1997, the Company entered into oil swap arrangements to cancel the effect of the swaps at a price of $18.85 per Bbl.

As of December 31, 1997, the Company had the following gas swap arrangements for periods after December 1997:

Months	Volume (MMBtu)	Houston Ship Channel Index Strike Price (Per MMBtu)
April 1998	600,000	$2.300
May 1998	620,000	2.215

The Company received $1.3 million as a premium for calls sold for January and February 1998 volumes of 2,480,000 MMBtu and 2,240,000 MMBtu, respectively. The January calls expired on December 31, 1997, the February calls expired on January 31, 1998, and the associated premiums will be recognized as income during the corresponding months of production.

The Company has also entered into the following collar transactions:

Months	Volume (MMBtu)	NYMEX Defined High Strike Price	NYMEX Defined Low Strike Price
March 1998	1,240,000	$2.69	$2.33
April 1998	1,200,000	2.48	2.11

These transactions require that the Company pay the counterparty if NYMEX exceeds the defined high strike price and that the counterparty pay the Company if NYMEX is less than the defined low strike price.

The Company entered into a curve lock for 4.9 Bcf of gas which allows the Company the option to hedge April 1999 through November 1999 gas based upon a negative $0.285 differential to December 1998 gas any time between the strike date and December 1998. A curve lock is a commodity swap arrangement that establishes, or hedges, a price differential between one commodity contract period and another. In markets where the forward curve is typically negatively sloped (near-term prices exceed deferred prices), an upward sloping price curve allows hedgers to lock in a deferred forward sale at a higher premium to a more prompt swap by a curve lock. For example, in the crude oil market, which typically has a negatively sloped price curve, it may be possible for a hedger to lock in a price relationship in which its deferred crude oil is sold at a premium to a prompter swap, because the price curve is upwardly sloping in the future. The expectation of the hedger is that either the market will return to its historically negatively sloped price curve, or that prices generally will increase and the curve lock swap will allow it to realize a premium price for the deferred versus the more prompt price.

Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the month of related production. The Company estimates that had all of the crude oil and natural gas swap agreements in effect for production periods beginning January 1, 1998 terminated on December 31, 1997, based on the closing prices for NYMEX futures contracts as of that date, the Company would have received a net amount of approximately $1.1 million from the counterparty which would have represented the "fair value" at that date. These agreements were not terminated.

CEMI periodically enters into various hedging transactions designed to hedge against physical purchase 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.

Risk Factors

Concentration of Unevaluated Leasehold in Louisiana

Chesapeake's future performance will be affected by the results from the development of its existing proved undeveloped reserves and unevaluated leasehold, including the Louisiana Trend and the Tuscaloosa Trend. As of December 31, 1997, Chesapeake had an investment in total unevaluated and unproved leasehold of approximately $125 million, of which approximately $66 million was located in the Louisiana Trend and the Tuscaloosa Trend. Approximately 42%, or $98 million, of Chesapeake's 1998 drilling budget is associated with drilling, construction of production facilities and seismic activity in the Louisiana Trend and the Tuscaloosa Trend. Failure of the Company's drilling activities to achieve anticipated quantities of economically attractive reserves and production would have an adverse impact on Chesapeake's operations and financial results and could result in future full-cost ceiling writedowns.

Impairment of Asset Value

Chesapeake reported full-cost ceiling writedowns of $110 million and $236 million during the Transition Period and the fiscal year ended June 30, 1997, respectively. Beginning in the quarter ended September 30, 1997, Chesapeake reduced its drilling budget for the Austin Chalk in the Louisiana Trend overall and concentrated remaining Austin Chalk drilling activity in the Masters Creek area. In addition, Chesapeake began to pursue a strategy to replace and expand its oil and gas reserves through acquisitions as a complement to its historical strategy of adding reserves through drilling. Chesapeake has also reduced its emphasis on acquiring unproved leasehold acreage to be developed through exploratory drilling. While these actions are intended to mitigate the higher risks associated with a growth strategy based on significant exploratory drilling, there can be no assurance that this change in strategy will result in enhanced future economic results or will prevent additional leasehold impairment and full-cost ceiling writedowns.

Since December 31, 1997, oil and gas prices have declined, with oil prices reaching ten-year lows in March 1998. In addition, the Company has completed several acquisitions based on expectations of higher oil and gas prices than those currently being received. Based on NYMEX oil prices of $16.50 per Bbl and NYMEX gas prices of $2.35 per Mcf in effect on March 25, 1998, and estimates of the Company's proved reserves as of December 31, 1997 (pro forma for the acquisitions completed during the quarter ended March 31, 1998), the Company estimates it will incur an additional full cost ceiling writedown of between $175 million and $200 million as of March 31, 1998. If this occurs, the Company will incur a substantial loss for the first quarter of 1998 which would further reduce shareholders' equity and reported earnings.

Following Chesapeake's announcement in late June 1997 of disappointing drilling results in the Louisiana Trend and a full-cost ceiling writedown, a number of purported class action lawsuits alleging violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 thereunder were filed against the Company and certain of its officers and directors. See "— Patent and Securities Litigation."

Risks of Acquisition Strategy

Acquisition Risks

The Company's growth strategy includes the acquisition of oil and gas properties. There can be no assurance, however, that the Company will be able to identify attractive acquisition opportunities, obtain financing for acquisitions on satisfactory terms or successfully acquire identified targets, including the pending Acquisitions. Future acquisitions may be financed through the incurrence of additional indebtedness to the extent permitted under the terms of the Company's then existing indebtedness or through the issuance of capital stock.

Furthermore, there can be no assurance that competition for acquisition opportunities in the oil and gas industry will not escalate, thereby increasing the cost to the Company of making further acquisitions or causing the Company to refrain from making additional acquisitions.

The Company is subject to risks that properties acquired by it and estimates of value made with respect to the properties acquired (including those acquired and to be acquired in the Acquisitions) will not perform as expected and that the returns from such properties will not support the indebtedness incurred or the other consideration used to acquire, or the capital expenditures needed to develop, such properties. The addition of the properties acquired and to be acquired in the Acquisitions may result in additional full cost ceiling writedowns to the extent the Company's capitalized costs of such properties exceed the estimated present value of the related proved reserves. In addition, expansion of the Company's operations may place a significant strain on the Company's management, financial and other resources. The Company's ability to manage future growth will depend upon its ability to monitor operations, maintain effective costs and other controls and significantly expand the Company's internal management, technical and accounting systems, all of which will result in higher operating expenses. Any failure to expand these areas and to implement and improve such systems, procedures and controls in an efficient manner at a pace consistent with the growth of the Company's business could have a material adverse effect on the Company's business, financial condition and results of operations. In addition, the integration of acquired properties with existing operations will entail considerable expenses in advance of anticipated revenues and may cause substantial fluctuations in the Company's operating results. There can be no assurance that the Company will be able to successfully complete each of the pending Acquisitions, or to successfully integrate the properties acquired and to be acquired in the Acquisitions or any other businesses it may acquire.

The Company has also acquired proved reserves in Canada. In addition to the risks described above, the acquisition of assets in Canada has the additional risks associated with currency exchange and valuation, foreign regulation and taxation, and severe climate and operating conditions.

Need to Replace Reserves; Substantial Capital Requirements

As is customary in the oil and gas exploration and production industry, Chesapeake's future success depends upon its ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Unless Chesapeake successfully replaces the reserves that it produces through successful development, exploration or acquisition, Chesapeake's proved reserves will decline. Further, approximately 43% of Chesapeake's estimated proved reserves at December 31, 1997 (17% pro forma for the Acquisitions) were located in the Austin Chalk formation in Texas and Louisiana, where wells are characterized by rapid decline rates. Additionally, approximately 47% of Chesapeake's total estimated proved reserves at December 31, 1997 were undeveloped. Recovery of such reserves will require significant capital expenditures and successful drilling operations. There can be no assurance that Chesapeake can successfully find and produce reserves economically in the future.

Chesapeake has made and intends to make substantial capital expenditures in connection with the exploration and production of its oil and gas properties and the acquisition of proved reserves. Historically, Chesapeake has funded its capital expenditure through a combination of internally generated funds, equity issuance and long-term and short-term debt financing arrangements. 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 Chesapeake's success in developing, acquiring and producing new reserves. If revenue were to decrease as a result of lower oil and gas prices, decreased production or increased costs, and Chesapeake's access to capital were limited, Chesapeake would have a reduced ability to replace its reserves or to maintain production at current levels, resulting in a decrease in production and revenue over time. If Chesapeake's cash flow from operations is not sufficient to fund its capital expenditure budget, there can be no assurance that additional debt or equity financing will be available to meet these requirements.

Substantial Indebtedness

As of December 31, 1997, and as a result of the loss incurred during the Transition Period, the Company's shareholders' equity was $280 million, versus long-term indebtedness of $509 million. Long-term indebtedness represented approximately 65% of total book capitalization. If the Company incurs additional full-cost ceiling writedowns, as anticipated, shareholders' equity will be further reduced. Standard & Poor's and Moody's Investors Service have recently indicated that the Company's credit ratings are under review with negative implications as a result of the Company's amount of indebtedness and full-cost ceiling writedowns.

The Company anticipates funding announced acquisitions and potential future acquisitions with a combination of commercial bank debt, long-term debt or preferred or common equity. If, as a result of general market conditions, additional losses, reduced credit ratings or for any other reason, the Company is unable to issue additional securities or borrow from commercial banks, the Company's liquidity would be impaired and growth potential reduced resulting in reduced earnings or losses.

Patent and Securities Litigation

The Company and its officers and directors are defendants in certain purported class actions based on federal and state securities fraud claims. In addition, the Company is defending claims of patent infringement, tortious interference with confidentiality contracts and misappropriation of proprietary information in another pending action. While no prediction can be made as to the outcome of these matters or the amount of damages that might be awarded, if any, an adverse result in any of them could be material to the Company. See Item 3. Legal Proceedings.

Governmental Regulation

Oil and gas operations are subject to various federal, state and local governmental regulations which may be changed from time to time in response to economic or political conditions. From time to time, regulatory agencies have imposed price controls and limitations on production in order to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. To date, expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant in relation to the results of operations of the Company. There can be no assurance that the trend of more expansive and stricter environmental legislation and regulations will not continue.

Competition

The Company operates in a highly competitive environment. The Company competes with major and independent oil and gas companies for the acquisition of desirable oil and gas properties, as well as for the equipment and labor required to develop and operate such properties. Many of these competitors have financial and other resources substantially greater than those of the Company.

Reliance on Key Personnel; Conflicts of Interest

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

Messrs. McClendon and Ward, together with another executive officer of the Company, have rights to participate in wells drilled by the Company on a quarter-by-quarter basis. Messrs. McClendon and Ward have elected to participate during all periods since the Company went public with individual interests of between 1.0% and 1.5%. Such participation may create interests which conflict with those of the Company.

Control by Certain Stockholders

At March 25, 1998, Aubrey K. McClendon, Tom L. Ward, the McClendon Children's Trust and the Ward Children's Trust beneficially owned an aggregate of 24,707,666 shares (including outstanding vested options), representing approximately 24% of the Company's outstanding Common Stock, and members of the Company's Board of Directors and senior management, including Messrs. McClendon and Ward and their respective children's trusts, beneficially owned an aggregate of 28,215,486 shares (including outstanding vested options), which represented approximately 27% of the Company's outstanding Common Stock. As a result, Messrs. McClendon and Ward, together with other officers and directors of the Company, are in a position to significantly influence matters requiring the vote or consent of the Company's 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 recently 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 it will be able to obtain, or be included under, such permits, where necessary, with minor modifications to existing facilities and operations that would not 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 oil-field 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 (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, none of which management believes will be materially adverse to the Company, individually or in the aggregate.

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 drilling activities involve greater risk of mechanical problems than conventional vertical 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 $60 million umbrella policy. The Company and its subsidiaries carry workers' compensation insurance in all states in which they operate and a $35 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 360 full-time employees as of December 31, 1997. No employees are represented by organized labor unions. The Company considers its employee relations to be good. The Company estimates that the number of full-time employees will increase by approximately 200 as the result of the Acquisitions.

Facilities

The Company owns 12 buildings totaling approximately 80,000 square feet and nine acres of land in an office complex in Oklahoma City that comprise its headquarters' offices. The Company also owns field offices in Lindsay and Waynoka, Oklahoma and leases office space in Wichita, Kansas, Oklahoma City, Oklahoma, College Station and Navasota, Texas, Lafayette, Louisiana and Calgary, Alberta, Canada. The Company plans to increase its office space within its Oklahoma City complex by constructing two buildings with approximately 90,000 aggregate square feet. This will allow the Company to consolidate the employees associated with the Acquisitions.

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.

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

Oil and Gas Reserves

The tables below set forth information as of December 31, 1997 with respect to the Company's estimated net proved reserves, the estimated future net revenue therefrom and the present value thereof at such date. Williamson Petroleum Consultants, Inc. evaluated 100% of the Company's Texas and Louisiana oil and gas reserves, together representing approximately 46% of the Company's total proved reserves. Excluding the reserves acquired from AnSon, Porter Engineering Associates evaluated 100% of the Company's oil and gas reserves in Oklahoma, New Mexico and the Williston area, together representing approximately 48% of the Company's total proved reserves. Of the oil and gas reserves acquired from AnSon, 85% were evaluated by Netherland, Sewell & Associates, Inc. The remaining AnSon properties, which represented approximately 2% of total proved reserves for the Company at December 31, 1997, 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, 1997	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)
Proved developed	10,087	178,082	238,604
Proved undeveloped	8,139	161,036	209,870
Total proved	18,226	339,118	448,474

Estimated Future Net Revenue as of December 31, 1997(a)	Proved Developed	Proved Undeveloped	Total Proved
		($ in thousands)	
Estimated future net revenue	$440,439	$274,659	$715,098
Present value of future net revenue	$306,368	$160,141	$466,509

(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, 1997. 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 average prices of $17.62 per barrel of oil and $2.29 per Mcf of gas.

The future net revenue attributable to the Company's estimated proved undeveloped reserves of $275 million at December 31, 1997, and the $160 million present value thereof, have been calculated assuming that the Company will expend approximately $153 million to develop these reserves through 2002. 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 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, 1997. 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. In the Transition Period and fiscal 1997, revisions to the Company's proved reserves contributed to a $110 million and a $236 million impairment of the Company's oil and gas properties, respectively. The uncertainties inherent in estimating quantities of proved reserves can also adversely impact acquisitions of proved reserves, since reserve estimates are used to arrive at acquisition value. See "Results of Operations — Impairment of Oil and Gas Properties" in Item 7.

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.

Securities Litigation. On January 13, 1998, a consolidated class action complaint styled In re Chesapeake Energy Corporation Securities Litigation was filed in the U.S. District Court for the Western District of Oklahoma. It consolidated twelve pending purported class actions filed in August and September 1997. The action is brought on behalf of purchasers of the Company's common stock and common stock options between January 25, 1996 and June 27, 1997. The defendants are the Company and the following officers and directors: Aubrey K. McClendon, Tom L. Ward, Marcus C. Rowland, Shannon T. Self, Walter C. Wilson, Henry J. Hood, Steven C. Dixon, J. Mark Lester and Ronald A. Lefaive. The complaint alleges violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 and Rule 10b-5 thereunder.

The plaintiffs assert that the defendants made material misrepresentations and failed to disclose material facts about the success of the Company's exploration and drilling activities in the Louisiana Trend. The complaint alleges the lack of disclosure artificially inflated the price of the Company's common stock during the period beginning January 25, 1996 and ending on June 27, 1997, when the Company issued a press release announcing disappointing drilling results in the Louisiana Trend and a full-cost ceiling writedown to be reflected in its June 30, 1997 financial statements. The plaintiffs further allege that certain of the named individual defendants sold the Company's common stock during the class period when they knew or should have known adverse nonpublic information. The plaintiffs seek a determination that the suit is a proper class action and damages in an unspecified amount, together with interest and costs of litigation, including attorneys' fees. The Company and the individual defendants believe that these claims are without merit and intend to defend against them vigorously.

Bayard Drilling Technologies, Inc. The following purported class actions alleging violations of Sections 11, 12(a) (2) and 15 of the Securities Act of 1933 and (with respect to the cases filed in state court) Section 408 of the Oklahoma Securities Act have been filed against the Company and others on behalf of investors who purchased common stock of Bayard Drilling Technologies, Inc. ("Bayard") in its initial public offering on November 4, 1997.

Michael W. Kahn v. Bayard, et al. filed in the District Court for Oklahoma County, Oklahoma on January 14, 1998.

Diane Burkett, Julian Swadel and Robert T. Greenberg v. Bayard, et al. filed in the District Court for Oklahoma County, Oklahoma on February 2, 1998.

Tom Yuan v. Bayard, et al. filed in the U.S. District Court for the Western District of Oklahoma on February 3, 1998.

The defendants in these actions 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 was a controlling person of Bayard by virtue of its ownership of 30.1% of Bayard's common stock outstanding prior to the offering, its prior financing relationship with Bayard involving terms allegedly favorable to the Company, its position as a customer of Bayard's drilling services under allegedly below-market terms, and the fact that Messrs. McClendon, Ward and Rowland, executive officers and directors of the Company, were formerly directors of Bayard.

Plaintiffs allege that the Bayard prospectus contained material omissions and misstatements relating to (i) the Company's financial "hardships", which purportedly caused the Company to coerce Bayard to proceed with the offering so that the Company could raise cash for itself and which impaired the Company's ability to continue providing Bayard with substantial drilling contracts, (ii) rising costs associated with Bayard's growth strategy and (iii) undisclosed pending related-party transactions between Bayard and third parties other than the Company. The alleged defective disclosures are claimed to have resulted in a decline in Bayard's share price following the public offering. Each plaintiff seeks 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. The Company believes that these actions are without merit and intends to defend against them vigorously.

UPRC Patent Suit. On October 15, 1996, Union Pacific Resources Company ("UPRC") filed suit against the Company in the U.S. District Court for the Northern District of Texas, Fort Worth Division, alleging (a) infringement and inducing infringement of UPRC's claims to a patent for an invention involving a method of maintaining a borehole in a stratigraphic zone during drilling, (b) tortious interference with contracts between UPRC and certain of its former employees regarding the confidentiality of proprietary information of UPRC and (c) misappropriation of such proprietary information. UPRC's claims against the Company are based on services provided to the Company by a third party vendor controlled by former UPRC employees. UPRC is seeking injunctive relief, damages of an unspecified amount, including actual, enhanced, consequential and punitive damages, interest, costs and attorneys' fees. The Company believes that it has meritorious defenses to UPRC's allegations and has requested the court to declare the UPRC patent invalid. The Company has also filed a motion to construe UPRC's patent claims and various motions for summary judgment. While no prediction can be made as to the outcome of the matter or the amount of damages that might be awarded, if any, in reports filed in the proceeding, experts for UPRC claim that damages could be as much as $18 million while Company experts state that the amount should not exceed $25,000, in each case based on the expert's view of a reasonable royalty for use of the patent.

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

The Company's annual meeting of shareholders was held on December 12, 1997. In addition to electing two directors, shareholders voted to amend the Company's Certificate of Incorporation to increase the authorized Common Stock to 250,000,000 shares.

In the election of directors, Breene M. Kerr received 62,066,255 votes for election and 4,630 shares withheld from voting. Walter C. Wilson received 62,047,653 votes for election and 23,232 shares withheld from voting. The proposal to amend the Company's Certificate of Incorporation to increase the authorized Common Stock was approved by a vote of 45,368,421 shares for, representing 64% of the outstanding shares of Common Stock, 5,471,569 shares voted against the proposal, 81,005 shares abstained from voting and 11,731,261 shares were broker non-votes.

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 (adjusted for 3-for-2 stock splits on December 15, 1995 and June 28, 1996 and a 2-for-1 stock split on December 31, 1996) of the Common Stock as reported by the New York Stock Exchange:

	Common Stock	
	High	Low
Fiscal year ended June 30, 1996:		
First Quarter	$ 7.28	$ 4.53
Second Quarter	11.08	6.20
Third Quarter	16.50	10.67
Fourth Quarter	30.38	15.50
Fiscal year ended June 30, 1997:		
First Quarter	34.00	21.00
Second Quarter	34.13	25.69
Third Quarter	31.50	19.88
Fourth Quarter	22.38	9.25
Transition Period ended December 31, 1997:		
First Quarter	11.50	6.31
Second Quarter	13.44	6.81

At March 25, 1998 there were 745 holders of record of Common Stock and approximately 27,000 beneficial owners.

Dividends

Since July 1997, the Company has paid quarterly dividends of $0.02 per common share. 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.

Certain of the Indentures governing the Company's outstanding Senior Notes contain certain restrictions on the Company's ability to declare and pay dividends. Under the Indentures, the Company may not pay any cash dividends in respect of its Common 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 Restricted Payments (as defined) 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.

Issuance of Common Stock

On December 16, 1997, the Company issued 3,792,724 shares of Common Stock to the shareholder of AnSon as part of the consideration for the Company's acquisition of all of the outstanding stock of AnSon. See Item 1. "Business — Recent and Pending Acquisitions". The shares were issued in a private transaction in reliance upon the exemption from registration afforded by Section 4(2) of the Securities Act of 1933.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated financial data of the Company for each of the five fiscal years ended June 30, 1997 and the Transition Period ended December 31, 1997. The data is derived from the Consolidated Financial Statements of the Company, including the Notes thereto, appearing elsewhere in this report. The data set forth in this 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 included elsewhere in this report.

	Six Months Ended December 31,		Year Ended June 30,				
	1997	1996	1997	1996	1995	1994	1993
	($ In Thousands, Except Per Share Data)						
STATEMENT OF OPERATIONS DATA:							
Revenues:							
Oil and gas sales	$ 95,657	$ 90,167	$ 192,920	$110,849	$ 56,983	$ 22,404	$11,602
Oil and gas marketing sales	58,241	30,019	76,172	28,428	—	—	—
Oil and gas service operations	—	—	—	6,314	8,836	6,439	5,526
Interest and other	78,966	2,516	11,223	3,831	1,524	981	880
Total revenues	232,864	122,702	280,315	149,422	67,343	29,824	18,008
Costs and expenses:							
Production expenses and taxes	10,094	5,874	15,107	8,303	4,256	3,647	2,890
Oil and gas marketing expenses	58,227	29,548	75,140	27,452	—	—	—
Oil and gas service operations	—	—	—	4,895	7,747	5,199	3,653
Impairment of oil and gas properties	110,000	—	236,000	—	—	—	—
Oil and gas depreciation, depletion and amortization	60,408	36,243	103,264	50,899	25,410	8,141	4,184
Depreciation and amortization of other assets	2,414	1,836	3,782	3,157	1,765	1,871	557
General and administrative	5,847	3,739	8,802	4,828	3,578	3,135	3,620
Provision for legal and other settlements	—	—	—	—	—	—	1,286
Interest and other	17,448	6,216	18,550	13,679	6,627	2,676	2,282
Total costs and expenses	264,438	83,456	460,645	113,213	49,383	24,669	18,472
Income (loss) before income taxes and extraordinary item	(31,574)	39,246	(180,330)	36,209	17,960	5,155	(464)
Provision (benefit) for income taxes	—	14,325	(3,573)	12,854	6,299	1,250	(99)
Income (loss) before extraordinary item	(31,574)	24,921	(176,757)	23,355	11,661	3,905	(365)
Extraordinary item:							
Loss on early extinguishment of debt, net of applicable income taxes	—	(6,443)	(6,620)	—	—	—	—
Net income (loss)	$(31,574)	$ 18,478	$(183,377)	$ 23,355	$ 11,661	$ 3,905	$ (365)
Earnings (loss) per common share basic:							
Income (loss) before extraordinary item	$ (0.45)	$ 0.40	$ (2.69)	$ 0.43	$ 0.22	$ 0.08	$ (0.02)
Extraordinary item	—	(0.10)	(0.10)	—	—	—	—
Net income (loss)	$ (0.45)	$ 0.30	$ (2.79)	$ 0.43	$ 0.22	$ 0.08	$ (0.02)
Earnings (loss) per common assuming dilution:							
Income (loss) before extraordinary item	$ (0.45)	$ 0.38	$ (2.69)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
Extraordinary item	—	(0.10)	(0.10)	—	—	—	—
Net income (loss)	$ (0.45)	$ 0.28	$ (2.79)	$ 0.40	$ 0.21	$ 0.08	$ (0.02)
Cash dividends declared per common share	$ 0.04	$ —	$ 0.02	$ —	$ —	$ —	$ —
CASH FLOW DATA:							
Cash provided by (used in) operating activities	$139,157	$ 41,901	$ 84,089	$120,972	$ 54,731	$ 19,423	$(1,499)
Cash used in investing activities	136,504	184,149	523,854	344,389	112,703	29,211	15,142
Cash provided by (used in) financing activities	(2,810)	231,349	512,144	219,520	97,282	21,162	20,802
BALANCE SHEET DATA (at end of period):							
Total assets	$952,784	$860,597	$ 949,068	$572,335	$276,693	$125,690	$78,707
Long-term debt, net of current maturities	508,992	220,149	508,950	268,431	145,754	47,878	14,051
Stockholders' equity	280,206	484,062	286,889	177,767	44,975	31,260	31,432

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

Overview

Chesapeake's revenue, operating cash flow (exclusive of changes in working capital) and production continued to reach record levels during the six months ended December 31, 1997 (the "Transition Period"). However, continuing unfavorable exploration and production results, primarily in the Austin Chalk Trend, together with increases in drilling and equipment costs and declines in oil prices as of December 31, 1997, resulted in downward revisions in estimates of Chesapeake's proved oil and gas reserves and the related present value of the estimated future net revenues from the Company's proved reserves. The Company recorded a $110.0 million asset writedown and a net loss of $31.6 million during the Transition Period.

In response to the losses recorded in fiscal 1997 and the Transition Period, Chesapeake significantly revised its business strategy during the Transition Period. These revisions included (i) reducing the size and risk of its exploratory drilling program, especially in the Louisiana Trend, (ii) acquiring significant volumes of long-lived natural gas reserves, particularly in the Mid-Continent region of the U.S., and (iii) building a larger inventory of lower risk drilling opportunities through acquisitions and joint ventures. Further, the Company has reduced its capital expenditure budget for exploration and development to more closely match anticipated cash flow from operations.

As part of this revised strategy, the Company has acquired or is in the process of acquiring various proved oil and gas reserves through merger or through purchases of oil and gas properties. Since October 1997, the Company has announced 10 transactions totaling approximately 716 Bcfe of proved reserves (the "Acquisitions"). Of these transactions, one was closed in December 1997, three were closed in the first quarter of 1998, and six are pending. These acquisitions will have the effect of increasing oil and gas production volumes and revenues, decreasing DD&A per Mcfe, and increasing production expenses and interest expense during 1998.

In November 1997, Chesapeake received net proceeds of approximately $90 million from its sale of Bayard common stock in the initial public offering of Bayard. Chesapeake recognized a gain on the sale of its Bayard stock of $73.8 million.

During the Transition Period, the Company participated in 86 gross (41.1 net) wells, of which 49 gross wells were Company operated. A summary of the Company's drilling activities and capital expenditures by primary operating area is as follows ($ in thousands):

	Gross Wells	Net Wells	Capital Expenditures: Drilling	Leasehold	Total
Mid-Continent Region	18	11.8	$ 64,247	$ 2,741	$ 66,988
Austin Chalk Trend	45	16.0	92,524	10,465	102,989
All other areas	23	13.3	44,210	12,310	56,520
Total	86	41.1	$200,981	$25,516	$226,497

The Company's proved reserves increased 11% to an estimated 448 Bcfe at December 31, 1997, up 45 Bcfe from 403 Bcfe of estimated proved reserves at June 30, 1997 (see Note 11 of Notes to Consolidated Financial Statements in Item 8 and "Results of Operations — Six Months Ended December 31, 1997 and 1996 — Impairment of Oil and Gas Properties"). Due to the numerous uncertainties inherent in drilling for oil and gas, 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, there can be no assurance that the Company's estimated proved reserves will not decrease in the future.

The Company's strategy for 1998 is to acquire proved oil and gas reserves, primarily in the Mid-Continent and in western Canada, and to continue developing oil and gas assets by drilling. The Company has reduced its capital expenditure budget for exploration and development drilling activities to approximately $225 million and has reduced the Austin Chalk Trend drilling component significantly. Furthermore, the Company has increased its use of 3-D seismic to assist in reducing exploratory risks and increasing economic returns from its drilling programs. The Company has conducted, participated in, or is actively pursuing more than 25 3-D seismic programs to evaluate the Company's acreage inventory.

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

	Six Months Ended December		Year Ended June 30,		
	1997	1996	1997	1996	1995
NET PRODUCTION DATA:					
Oil (MBbl)	1,857	1,116	2,770	1,413	1,139
Gas (MMcf)	27,326	30,095	62,005	51,710	25,114
Gas equivalent (MMcfe)	38,468	36,791	78,625	60,190	31,947
OIL AND GAS SALES ($ in 000's):					
Oil	$34,523	$24,418	$ 57,974	$ 25,224	$19,784
Gas	61,134	65,749	134,946	85,625	37,199
Total oil and gas sales	$95,657	$90,167	$192,920	$110,849	$56,983
AVERAGE SALES PRICE:					
Oil ($ per Bbl)	$ 18.59	$ 21.88	$ 20.93	$ 17.85	$ 17.36
Gas ($ per Mcf)	$ 2.24	$ 2.18	$ 2.18	$ 1.66	$ 1.48
Gas equivalent ($ per Mcfe)	$ 2.49	$ 2.45	$ 2.45	$ 1.84	$ 1.78
OIL AND GAS COSTS ($ per Mcfe):					
Production expenses and taxes	$ .27	$ .16	$ .19	$ .14	$ .13
General and administrative	$ .15	$ .10	$ .11	$ .08	$ .11
Depreciation, depletion and amortization	$ 1.57	$ .99	$ 1.31	$ .85	$ .80
NET WELLS DRILLED:					
Horizontal wells	27.2	34.3	75.7	42.0	28.5
Vertical wells	13.9	13.0	31.3	27.0	23.0
NET WELLS AT END OF PERIOD	401.0	210.3	270.1	187.0	96.4

Results of Operations

Six Months Ended December 31, 1997 and 1996

General. For the Transition Period, the Company realized a net loss of $31.6 million, or $0.45 per common share, on total revenues of $232.9 million. This compares to net income of $18.5 million, or $0.28 per common share, on total revenues of $122.7 million in the six months ended December 31, 1996 (the "Prior Period"). The loss in the Transition Period was caused by a $110.0 million asset writedown recorded under the full cost method of accounting, partially offset by a gain of $73.8 million from the sale of the Bayard stock. See "Impairment of Oil and Gas Properties".

Oil and Gas Sales. During the Transition Period, oil and gas sales increased 6% to $95.7 million versus $90.2 million for the Prior Period. The increase in oil and gas sales resulted primarily from growth in production volumes. For the Transition Period, the Company produced 38.5 Bcfe at a weighted average price of $2.49 per Mcfe, compared to 36.8 Bcfe produced in the Prior Period at a weighted average price of $2.45 per Mcfe.

The following table shows the Company's production by region for the Transition Period and the Prior Period:

	For the Six Months Ended December 31,			
	1997		1996	
	(MMcfe)	Percent	(MMcfe)	Percent
Mid-Continent Region	8,852	23%	8,980	24%
Austin Chalk Trend	26,220	68	26,243	71
All other fields	3,396	9	1,568	5
Total production	38,468	100%	36,791	100%

Natural gas production represented approximately 71% of the Company's total production volume on an equivalent basis in the Transition Period, compared to 82% in the Prior Period. This decrease in gas production as a percentage of total production was primarily the result of new production in the Louisiana Trend, which tends to produce more oil than gas.

For the Transition Period, the Company realized an average price per barrel of oil of $18.59, compared to $21.88 in the Prior Period. Gas price realizations increased slightly from $2.18 per Mcf in the Prior Period to $2.24 per Mcf in the Transition Period. The Company's hedging activities resulted in decreases in oil and gas revenues of $4.3 million and $7.1 million in the Transition Period and Prior Period, respectively. Oil prices received in the first quarter of 1998 are significantly below prices realized in the Transition Period, which has the effect of reducing oil revenues and decreasing earnings.

Oil and Gas Marketing Sales. The Company realized $58.2 million in oil and gas marketing sales for third parties in the Transition Period, with corresponding oil and gas marketing expenses of $58.2 million. This compares to sales of $30.0 million, expenses of $29.5 million, and a margin of $0.5 million in the Prior Period.

Interest and Other. Interest and other revenues for the Transition Period were $79.0 million compared to $2.5 million in the Prior Period. During the Transition Period, 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 revenues.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and excise taxes, increased to $10.1 million in the Transition Period, compared to $5.9 million in the Prior Period. These increases were primarily the result of increased operating costs and increased production. On a unit of production basis, production expenses and taxes increased to $0.27 per Mcfe compared to $0.16 per Mcfe in the Prior Period. The Company expects that production expenses and taxes per Mcfe will increase in 1998, primarily as the result of completed and anticipated acquisitions that generally have higher associated lifting costs per unit than the Company's historical production.

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. To the extent that capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the discounted future net revenues of proved oil and gas properties, such excess costs are charged to operations.

The Company incurred an impairment of oil and gas properties charge of $110 million for the Transition Period. This writedown was caused by several factors, including oil prices declining from $18.38 at June 30, 1997 to $17.62 at December 31, 1997, and drilling and completion costs continuing to escalate during the

Transition Period. Higher costs caused the Company's capital spending to exceed budgeted amounts during the Transition Period and also increased the estimated future capital expenditures to be incurred to develop the Company's proved undeveloped reserves. The Company's results from wells completed during the Transition Period in the Louisiana Trend continued to be inconsistent and production performance from various properties in the Navasota River and Independence areas were lower than projected at June 30, 1997. As a result of the above factors, the Company recorded a downward revision to its proved reserves of 38 net Bcfe in the Austin Chalk Trend as of December 31, 1997.

Excluding the purchase of additional leasehold, the Company incurred approximately $85 million in capital expenditures in the Louisiana Trend during the Transition Period, of which approximately $67 million were incurred in the Masters Creek area. Approximately $16 million of the drilling costs were incurred on Company operated wells that had not been completed at December 31, 1997.

In the Masters Creek area, the Company completed operations on 11 wells during the Transition Period. Although 10 of the 11 wells were commercially productive, the drilling costs incurred through December 31, 1997 of approximately $58 million for the 10 wells were higher than anticipated and assigned reserves were lower than expected. The lower reserve quantities were due in part to lower oil prices at December 31, 1997. In addition, the Company transferred approximately $11 million of previously unevaluated leasehold costs from all areas of the Louisiana Trend to the amortization base of the full cost pool during the Transition Period.

In connection with the Company's acquisition of AnSon in December 1997, which was accounted for using the purchase method, the purchase price of approximately $43 million was allocated to the fair value of assets acquired. Based upon reserve estimates as of December 31, 1997, the portion of the purchase price which was allocated to evaluated oil and gas properties exceeded the associated discounted future net revenues from AnSon's estimated proved reserves by approximately $14 million.

Since December 31, 1997, oil and gas prices have declined, with oil prices reaching ten-year lows in March 1998. In addition, the Company has completed several acquisitions based on expectations of higher oil and gas prices than those currently being received. Based on NYMEX oil prices of $16.50 per Bbl and NYMEX gas prices of $2.35 per Mcf in effect on March 25, 1998, and estimates of the Company's proved reserves as of December 31, 1997 (pro forma for the acquisitions completed during the quarter ended March 31, 1998), the Company estimates it will incur an additional full cost ceiling writedown of between $175 million and $200 million as of March 31, 1998. If this occurs, the Company will incur a substantial loss for the first quarter of 1998 which would further reduce shareholders' equity.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization ("DD&A") of oil and gas properties for the Transition Period was $60.4 million, $24.2 million higher than the Prior Period's expense of $36.2 million. The expense in the Transition Period was computed prior to the writedown from the Impairment of oil and gas properties charge. 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, increased to $1.57 in the Transition Period compared to $0.99 in the Prior Period. The Company's DD&A rate in the future will be a function of the results of future acquisition, exploration, development and production costs and results, and asset writedowns, if any. The Company's DD&A rate is expected to be positively affected as the result of the acquisitions completed and pending.

Depreciation and Amortization of Other Assets. Depreciation and amortization ("D&A") of other assets increased to $2.4 million in the Transition Period, compared to $1.8 million in the Prior Period. This increase 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 March 1997. The Company anticipates an increase in D&A in 1998 as a result of higher building depreciation expense on the Company's corporate offices.

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 $5.8 million in the Transition Period, up 56% from $3.7 million in the Prior Period. The increase in the

Transition Period compared to the Prior Period results primarily from increased personnel expenses required by the Company's growth and industry wage inflation. The Company capitalized $2.4 million of internal costs in the Transition Period directly related to the Company's oil and gas exploration and development efforts, compared to $1.1 million in the Prior Period. The Company anticipates that G&A costs for 1998 will continue to increase as the result of industry wage inflation, legal fees associated with the UPRC and shareholder litigation, and increases in employment due to the completed and pending acquisitions.

Interest and Other. Interest and other expense increased to $17.4 million in the Transition Period, compared to $6.2 million in the Prior Period. The increase was due primarily to the issuance of $300 million of Senior Notes in March 1997. In addition to the interest expense reported, the Company capitalized $5.1 million of interest during the Transition Period, compared to $7.6 million capitalized in the Prior Period.

Provision (Benefit) for Income Taxes. The Company recorded no income taxes for the Transition Period, compared to income tax expense of $14.3 million in the Prior Period, before consideration of the $3.7 million tax benefit associated with the extraordinary loss from the early extinguishment of debt.

At December 31, 1997, the Company had a net operating loss carryforward of approximately $337 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 carryforward, will be realizable in future years, and therefore a valuation allowance of $77.9 million has been recorded. No deferred tax benefit related to the exercise of employee stock options was allocated to additional paid-in capital in the Transition Period. The Company does not expect to record any net income tax expense in 1998 based on information available at this time.

Fiscal Years Ended June 30, 1997, 1996, 1995

General. For the fiscal year ended June 30, 1997, the Company realized a net loss of $183.4 million, or $2.79 per common share, on total revenues of $280.3 million. This compares to net income of $23.4 million, or $0.40 per common share, on total revenues of $149.4 million in 1996, and net income of $11.7 million, or $0.21 per common share, on total revenues of $67.3 million in fiscal 1995. The loss in fiscal 1997 resulted from a $236 million asset writedown recorded in the fourth quarter under the full cost method of accounting. See "— Impairment of Oil and Gas Properties".

Oil and Gas Sales. During fiscal 1997, oil and gas sales increased 74% to $192.9 million versus $110.8 million for fiscal 1996 and 238% from the fiscal 1995 amount of $57.0 million. The increase in oil and gas sales resulted primarily from strong growth in production volumes and significantly higher average oil and gas prices. For fiscal 1997, the Company produced 78.6 Bcfe at a weighted average price of $2.45 per Mcfe, compared to 60.2 Bcfe produced in fiscal 1996 at a weighted average price of $1.84 per Mcfe, and 31.9 Bcfe produced in fiscal 1995 at a weighted average price of $1.78 per Mcfe. This represents production growth of 31% for fiscal 1997 compared to fiscal 1996 and 146% compared to fiscal 1995.

The following table shows the Company's production by region for fiscal 1997 and fiscal 1996:

	For the Year Ended June 30,			
	1997		1996	
	(MMcfe)	Percent	(MMcfe)	Percent
Mid-Continent Region	17,370	22%	10,420	17%
Austin Chalk Trend	57,377	73	47,234	78
Other fields	3,878	5	2,536	5
Total Production	78,625	100%	60,190	100%

Natural gas production represented approximately 79% of the Company's total production volume on an equivalent basis in fiscal 1997. This compares to 86% in fiscal 1996 and 79% in fiscal 1995. This decrease in gas production as a percentage of total production in fiscal 1997 was the result of drilling in the Louisiana Trend, which tends to produce more oil than gas.

For fiscal 1997, the Company realized an average price per barrel of oil of $20.93, compared to $17.85 in fiscal 1996 and $17.36 in fiscal 1995. The Company markets its oil on monthly average equivalent spot price contracts and typically receives a premium to the price posted for West Texas Intermediate crude oil.

Gas price realizations increased from fiscal 1996 to 1997 from $1.66 per Mcf to $2.18 per Mcf, or 31%, generally as the result of market conditions. Gas prices in fiscal 1995 averaged $1.48 per Mcf. The Company's gas price realizations in fiscal 1997 were also higher due to the increase in Louisiana Trend gas production, which generally receives premium prices at least equivalent to Henry Hub indexes due to the high Btu content and favorable market location of the production.

The Company's hedging activities resulted in decreases in oil and gas revenues of $7.4 million, $5.9 million, and none in fiscal 1997, 1996 and 1995, respectively.

Oil and Gas Marketing Sales. In December 1995, the Company entered into the oil and gas marketing business by acquiring a subsidiary to provide 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 geographical areas in which the Company is active. The Company realized $76.2 million in oil and gas marketing sales for third parties in fiscal 1997, with corresponding oil and gas marketing expenses of $75.1 million, resulting in a gross margin of $1.1 million. This compares to sales of $28.4 million, expenses of $27.5 million, and a margin of $0.9 million in fiscal 1996. There were no comparable marketing activities in fiscal 1995.

Oil and Gas Service Operations. On June 30, 1996, Peak USA Energy Services, Ltd., a limited partnership ("Peak"), was formed by Peak Oilfield Services Company (a joint venture between Cook Inlet Region, Inc. and Nabors Industries, Inc.) and Chesapeake for the purpose of purchasing the Company's oilfield service assets and providing rig moving, transportation and related site construction services to the Company and others in the industry. The Company sold its service company assets to Peak for $6.4 million, and simultaneously invested $2.5 million in exchange for a 33.3% partnership interest in Peak. This transaction resulted in recognition of a $1.8 million pre-tax gain during the fourth fiscal quarter of 1996 (reported in Interest and other revenues). A deferred gain from the sale of service company assets of $0.9 million was recorded as a reduction in the Company's investment in Peak and is being amortized to income over the estimated useful lives of the Peak assets. The Company's investment in Peak is accounted for using the equity method, and resulted in $0.5 million of income being included in Interest and other revenues in fiscal 1997.

Revenues from oil and gas service operations were $6.3 million in fiscal 1996, down 28% from $8.8 million in fiscal 1995. The related costs and expenses of these operations were $4.9 million and $7.7 million for the two years ended June 30, 1996 and 1995 respectively. The gross profit margin of 22% in fiscal 1996 was up from the 12% margin in fiscal 1995. The gross profit margin derived from these operations is a function of drilling activities in the period, costs of materials and supplies and the mix of operations between lower margin trucking operations versus higher margin labor oriented service operations.

Interest and Other. Interest and other revenues for fiscal 1997 were $11.2 million compared to $3.8 million in fiscal 1996 and $1.5 million in fiscal 1995. During fiscal 1997, the Company realized $8.7 million in interest, $1.6 million of other investment income, $0.5 million from its investment in Peak, and $0.4 million in other income. During fiscal 1996, the Company realized $3.7 million of interest and other investment income and a $1.8 million gain related to the sale of certain service company assets, offset by a $1.7 million loss due to natural gas basis changes in April 1996 as a result of the Company's hedging activities. During 1995, the Company did not incur any such gains on sale of assets or basis losses.

Production Expenses and Taxes. Production expenses and taxes, which include lifting costs, production taxes and excise taxes, increased to $15.1 million in fiscal 1997, compared to $8.3 million in fiscal 1996 and $4.3 million in fiscal 1995. These increases on a year-to-year basis were primarily the result of increased production. On a unit production basis, production expenses and taxes increased to $0.19 per Mcfe, compared to $0.14 per Mcfe in fiscal 1996 and $0.13 per Mcfe in fiscal 1995. During fiscal 1996 and 1995, a high proportion of the Company's production was from the Giddings Field, much of which qualified for Texas severance tax exemptions.

Impairment of Oil and Gas Properties. Prior to January 1997, the Company had completed operations on one exploratory well in each of three separate areas outside Masters Creek in the Louisiana Trend. Between April 1997 and July 1997, the Company completed operations on 10 Company operated exploratory wells located outside Masters Creek in the Louisiana Trend that resulted in the addition of only 0.5 Bcfe of proved reserves. Cumulative well costs on these non-Masters Creek properties were approximately $43 million as of June 30, 1997. Of the ten wells, one was completed on April 15, 1997, one on May 3, 1997 and eight after June 1, 1997. Based upon this information and similar data which had become available from outside operated properties in these non-Masters Creek areas of the Louisiana Trend, management determined that a significant portion of its leasehold in the Louisiana Trend outside of Masters Creek was impaired. During the quarters ended March 31, 1997 and June 30, 1997, the Company transferred $7.6 million and $86.3 million, respectively, of non-Masters Creek Louisiana Trend leasehold costs to the amortization base of the full cost pool.

Oil and gas prices declined from $20.90 per Bbl and $2.41 per Mcf at June 30, 1996 to $18.38 per Bbl and $2.12 per Mcf at June 30, 1997. Drilling and equipment costs escalated rapidly in the fourth quarter of fiscal 1997 due primarily to higher day rates for drilling rigs, thus increasing the estimated future capital expenditures to be incurred to develop the Company's proved undeveloped reserves. The oil and gas price declines and the increased costs to drill and equip wells caused the Company to eliminate 35 gross proved undeveloped locations in the Knox Field which contained an estimated 45 net Bcfe of proved undeveloped reserves. Similar factors combined with unfavorable drilling and production results eliminated approximately 93 Bcfe of proved reserves in the Giddings and Louisiana Trend areas.

In the Independence area of the Giddings Field of Texas, a single well completed in late March 1997, which the Company had estimated to contain 15.7 Bcfe of Company reserves at March 31, 1997, was significantly and adversely affected by another operator's offset well which damaged the reservoir and reduced the Company's estimated ultimate recovery to 8.0 Bcfe of reserves.

In late June 1997, management reviewed its March 31, 1997 internal estimates of proved reserves and related present value and, after giving effect to the fourth quarter 1997 drilling and production results, oil and gas prices, higher drilling and completion costs, and additional leasehold acquisition costs and delay rentals, determined that the Company had less reserve potential than had previously been estimated. As a result, management estimated that at June 30, 1997 the Company would have capitalized costs of oil and gas properties which would exceed its full cost ceiling by approximately $150 million to $200 million. On June 27, 1997, the Company issued a press release which included this estimate. Subsequently, based on the Company's final year-end estimates of its proved reserves and related estimated future net revenues, which took into account additional drilling and production results, management determined that as of June 30, 1997, its capitalized costs exceeded its full cost ceiling by approximately $236 million. No such writedown was experienced by the Company in fiscal 1996 or fiscal 1995.

Oil and Gas Depreciation, Depletion and Amortization. DD&A of oil and gas properties for fiscal 1997 was $103.3 million, $52.4 million higher than fiscal 1996's expense of $50.9 million, and $77.9 million higher than fiscal 1995's expense of $25.4 million. The expense in fiscal 1997 excluded the effects of the asset writedown. 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, increased to $1.31 in fiscal 1997 compared to $0.85 in fiscal 1996 and $0.80 in fiscal 1995.

Depreciation and Amortization of Other Assets. D&A of other assets increased to $3.8 million in fiscal 1997, compared to $3.2 million in fiscal 1996 and $1.8 million in fiscal 1995. This increase in fiscal 1997 was caused by an increase in D&A as a result of increased investments in depreciable buildings and equipment and increased amortization of debt issuance costs as a result of the issuance of Senior Notes in May 1995, April 1996 and March 1997.

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 $8.8 million in fiscal 1997, up 83% from $4.8 million in fiscal 1996 and up from $3.6 million in fiscal 1995. The increases in fiscal 1997 compared to fiscal 1996 and 1995 result primarily from increased personnel expenses required by the

Company's growth and industry wage inflation. The Company capitalized $3.9 million of internal costs in fiscal 1997 directly related to the Company's oil and gas exploration and development efforts, compared to $1.7 million in 1996 and $0.6 million in 1995.

Interest and Other. Interest and other expense increased to $18.6 million in fiscal 1997 as compared to $13.7 million in 1996 and $6.6 million in fiscal 1995. Interest expense in the fourth quarter of fiscal 1997 was $8.7 million, reflecting the issuance of $300 million of Senior Notes in March 1997. In addition to the interest expense reported, the Company capitalized $12.9 million of interest during fiscal 1997, compared to $6.4 million capitalized in fiscal 1996 and $1.6 million in fiscal 1995.

Provision (Benefit) for Income Taxes. The Company recorded an income tax benefit of $3.6 million for fiscal 1997, before consideration of the $3.8 million tax benefit associated with the extraordinary loss from the early extinguishment of debt, compared to income tax expense of $12.9 million in 1996 and $6.3 million in 1995. All of the income tax expense in 1996 and 1995 was deferred due to tax net operating losses and carryovers resulting from the Company's drilling program.

The Company's loss before income taxes and extraordinary item of $180.3 million created a tax benefit for financial reporting purposes of $67.7 million. However, due to limitations on the recognition of deferred tax assets, the total tax benefit was reduced to $3.6 million.

At June 30, 1997, the Company had a net operating loss carryforward of approximately $300 million for regular federal income taxes which will expire in future years beginning in 2007. Management believed that it could not be demonstrated at that time that it was more likely than not that the deferred income tax assets, comprised primarily of the net operating loss carryforward, would be realizable in future years, and therefore a valuation allowance of $64.1 million was recorded in fiscal 1997. A deferred tax benefit related to the exercise of employee stock options of approximately $4.8 million was allocated directly to additional paid-in capital in 1997, compared to $7.9 million in 1996 and $1.2 million in fiscal 1995.

Hedging

Periodically the Company utilizes hedging strategies to hedge the price of a portion of its future oil and gas production. These strategies include (1) 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, (2) 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, (3) 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 (4) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points. Results from 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 hedging transactions related to the Company's oil and gas production volumes or CEMI and AGM physical purchase or sale commitments.

As of December 31, 1997, the Company had the following oil swap arrangements for periods after December 1997:

Month	Volume (BBls)	NYMEX Index Strike Price (Per Bbl)
January through June 1998	724,000	$19.82

After year-end 1997, the Company entered into oil swap arrangements to cancel the effect of the swaps at a price of $18.85 per Bbl.

As of December 31, 1997, the Company had the following gas swap arrangements for periods after December 1997:

Months	Volume (MMBtu)	Houston Ship Channel Index Strike Price (Per MMBtu)
April 1998	600,000	$2.300
May 1998	620,000	$2.215

The Company received $1.3 million as a premium for calls sold for January and February 1998 volumes of 2,480,000 MMBtu and 2,240,000 MMBtu, respectively. The January calls expired on December 31, 1997, the February calls expired on January 31, 1998, and the associated premiums will be recognized as income during the corresponding months of production.

The Company has also entered into the following collar transactions:

Months	Volume (Mmbtu)	NYMEX Defined High Strike Price	NYMEX Defined Low Strike Price
March 1998	1,240,000	$2.69	$2.33
April 1998	1,200,000	$2.48	$2.11

These transactions require that the Company pay the counterparty if NYMEX exceeds the defined high strike price and that the counterparty pay the Company if NYMEX is less than the defined low strike price.

The Company entered into a curve lock for 4.9 Bcf of gas which allows the Company the option to hedge April 1999 through November 1999 gas based upon a negative $0.285 differential to December 1998 gas any time between the strike date and December 1998. A curve lock is a commodity swap arrangement that establishes, or hedges, a price differential between one commodity contract period and another. In markets where the forward curve is typically negatively sloped (near-term prices exceed deferred prices), an upward sloping price curve allows hedgers to lock in a deferred forward sale at a higher premium to a more prompt swap by a curve lock. For example, in the crude oil market, which typically has a negatively sloped price curve, it may be possible for a hedger to lock in a price relationship in which its deferred crude oil is sold at a premium to a prompter swap, because the price curve is upwardly sloping in the future. The expectation of the hedger is that either the market will return to its historically negatively sloped price curve, or that prices generally will increase and the curve lock swap will allow it to realize a premium price for the deferred versus the more prompt price.

Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the month of related production. The Company estimates that had all of the crude oil and natural gas swap agreements in effect for production periods beginning January 1, 1998 terminated on December 31, 1997, based on the closing prices for NYMEX futures contracts as of that date, the Company would have received a net amount of approximately $1.1 million from the counterparty which would have represented the "fair value" at that date. These agreements were not terminated.

Periodically, CEMI enters into various hedging transactions designed to hedge against physical purchase 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.

Liquidity and Capital Resources

For the Six Months Ended December 31, 1997 and 1996

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in components of working capital) increased to $139.2 million in the Transition Period, compared to $41.9 million in the Prior Period. The primary reason for the increase was significant changes in the components of current assets and liabilities, specifically $92 million of short-term investments which were converted into cash during the Transition Period. Cash provided by operating activities is expected to be a significant source for meeting the forecasted cash requirements for 1998.

Cash Flows from Investing Activities. Cash used in investing activities decreased to $136.5 million in the Transition Period, compared to $184.1 million in the Prior Period. This decrease in cash used in investing activities was due primarily to the $90.4 million received from the sale of the Company's investment in Bayard common stock during the Transition Period, offset by other investments. Approximately $189.8 million was expended by the Company in the Transition Period for development and exploration of oil and gas properties, as compared to $186.8 million in the Prior Period. In the Transition Period, other property and equipment additions were $27.0 million primarily as a result of its $11.9 million investment in the Louisiana Chalk Gathering System and Masters Creek Gas Plant as well as additional investments in its Oklahoma City office complex.

Cash Flows from Financing Activities. Cash used in financing activities was $2.8 million during the Transition Period, compared to cash provided by financing activities of $231.3 million during the Prior Period. The decrease was due primarily to the proceeds received from the issuance of common stock during the Prior Period of $288.1 million, which was partially offset by the net payments on long-term borrowings of $56.8 million during the Prior Period.

For the Fiscal Years Ended June 30, 1997, 1996 and 1995

Cash Flows from Operating Activities. Cash provided by operating activities (inclusive of changes in components of working capital) decreased to $84.1 million in fiscal 1997, compared to $121.0 million in fiscal 1996 and $54.7 million in fiscal 1995. The primary reason for the decrease from fiscal 1996 to 1997 was significant changes in the components of current assets and liabilities, specifically $102.9 million of short-term investments at June 30, 1997.

Cash Flows from Investing Activities. Significantly higher cash was used in fiscal 1997 for development, exploration and acquisition of oil and gas properties compared to fiscal 1996 and 1995. Approximately $524 million was expended by the Company in fiscal 1997 (net of proceeds from sale of leasehold, equipment and other), compared to $344 million in fiscal 1996. In fiscal 1995 the Company expended $113 million (net of proceeds from sale of leasehold, equipment and other). Net cash proceeds received by the Company for sales of oil and gas equipment, leasehold and other decreased to approximately $3.1 million in fiscal 1997, compared to $6.2 million in fiscal 1996 and $12.0 million in fiscal 1995. In fiscal 1997, other property and equipment additions were $34 million primarily as a result of its $16.8 million investment in the Louisiana Chalk Gathering System and Masters Creek Gas Plant as well as additional investments in its Oklahoma City office complex.

Cash Flows from Financing Activities. On December 2, 1996, the Company completed a public offering of 8,972,000 shares of Common Stock at a price of $33.63 per share resulting in net proceeds to the Company of approximately $288.1 million. Approximately $55.0 million of the proceeds was used to defease the Company's $47.5 million Senior Notes due 2001, and $11.2 million of the proceeds was used to retire all amounts outstanding under the Company's commercial bank credit facilities.

On March 17, 1997, the Company concluded the sale of $150 million of 7.875% Senior Notes due 2004 (the "7.875% Senior Notes"), and $150 million of 8.5% Senior Notes due 2012 (the "8.5% Senior Notes"), which offering resulted in net proceeds to the Company of approximately $292.6 million. The 7.875% Senior Notes were issued at 99.92% of par and the 8.5% Senior Notes were issued at 99.414% of par. The 7.875% Senior Notes and the 8.5% Senior Notes are redeemable at the option of the Company at any time at the redemption or make-whole prices set forth in the respective Indentures.

In fiscal 1996, cash flows from financing activities were $219.5 million, largely as the result of the issuance of 5,989,500 shares of Common Stock (net proceeds to the Company of approximately $99.4 million) and $120 million of 9.125% Senior Notes due 2006 (the "9.125% Senior Notes"). The Company may, at its option, redeem prior to April 15, 1999 up to $42 million principal amount of the 9.125% Senior Notes at 109.125% of the principal amount thereof from equity offering proceeds. The 9.125% Senior Notes are redeemable at the option of the Company at any time at the redemption or make-whole prices set forth in the Indenture.

Financial Flexibility and Liquidity

The Company had working capital of $64.2 million at December 31, 1997. In January 1998, the Company arranged a $500 million revolving credit facility with a group of commercial banks. The facility has an initial committed borrowing base of $200 million ($168 million until the acquisition of DLB Oil & Gas, Inc. is consummated), of which $120 million was used to pay off bank debt assumed in the acquisition of Hugoton Energy Corporation on March 10, 1998 and the remainder is anticipated to be used for other acquisitions. The borrowing base can be expanded as other acquisitions create collateral value. Borrowings under the facility are secured by CAC's pledge of its subsidiaries' capital stock and bear interest currently at a rate equal to the Eurodollar rate plus 1.5%.

The borrower under this facility is Chesapeake Acquisition Corporation ("CAC"), a wholly-owned subsidiary of the Company. CAC is an "unrestricted subsidiary" under the terms of the Company's Senior Note Indentures and is not a guarantor of the senior note indebtedness. The Company is not a guarantor of the revolving credit facility.

The Senior Note Indentures contain various restrictions for the Company and its restricted subsidiaries to incur additional indebtedness. As of December 31, 1997, the Company estimates that commercial bank indebtedness of $75 million could have been incurred within these restrictions. This restriction does not apply to borrowings incurred by CAC and other unrestricted subsidiaries.

Debt ratings for the Senior Notes are Ba3 by Moody's Investors Service and BB- by Standard & Poor's Corporation as of March 25, 1998, although both have recently placed the Company on review with negative implications. The Company's long-term debt represented approximately 65% of total capital at December 31, 1997. There are no scheduled principal payments required on any of the Senior Notes until June 2002.

The Company believes it has adequate resources, including budgeted cash flow from operations, to fund its capital expenditure budget for exploration and development activities during 1998, which is currently estimated to be approximately $235 million. However, continued low oil prices or unfavorable drilling results could cause the Company to further reduce its drilling program, which is largely discretionary. Additional acquisitions, if any, beyond the announced acquisitions will be funded by a combination of commercial bank debt and/or the issuance of additional public debt or equity securities. If these additional resources are not available, the Company may not be able to successfully pursue its revised 1998 business strategy.

Year 2000

Year 2000 issues result from the inability of computer programs or computerized equipment to accurately calculate, store or use a date subsequent to December 31, 1999. Although the erroneous date can be interpreted in a number of different ways typically the year 2000 is interpreted by the computer as the year 1900. This could result in a system failure or miscalculations causing disruptions of operations, including, among other things, a temporary inability to process transactions, send invoices, or engage in similar normal business.

The Company has completed an assessment of its core financial and operational software systems and has found them either already in compliance or the necessary steps to bring them into compliance have been identified. These tasks are scheduled for completion by December 31, 1998. The Company believes that the successful completion of these tasks will mitigate any critical Year 2000 issues. However, if these tasks are not completed by year-end 1999, the Year 2000 issue could have a material impact on the Company's ability to meet financial and reporting requirements. It should not impact the Company's ability to continue exploration, drilling or production activities.

Assessment of other less critical software systems and various types of equipment is continuing and should be completed by September 1998. The Company believes that the potential impact, if any, of these systems not being Year 2000 compliant will at most require employees to manually complete otherwise automated tasks or calculations.

Following the completion of the aforementioned assessment, the Company will initiate formal communication with its significant suppliers, business partners and customers to determine the extent to which the Company is vulnerable to those third parties' failure to correct their own Year 2000 issues. However, there can be no guarantee that the systems of other companies on which the Company's systems rely will be timely converted, or that a failure to convert by another company, or a conversion that is incompatible with the Company's systems would not have a material adverse effect on the Company. The Company has determined it has no exposure to contingencies related to the Year 2000 issue for the products it has sold.

The Company will utilize both internal and external resources to complete tasks and perform testing necessary to address the Year 2000 issue. Completion of the Year 2000 project is based on management's best estimates, which were derived utilizing numerous assumptions of future events including the continued availability of certain resources, third party modification plans and other factors. However, there can be no guarantee that these estimates will be achieved and actual results could differ materially from those plans. Specific factors that might cause such material differences include, but are not limited to, the availability and cost of personnel trained in this area, the ability to locate and correct all relevant computer codes, and similar uncertainties.

Forward Looking Statements

The information contained in this Form 10-K includes certain forward-looking statements. When used in this document, the words budget, budgeted, anticipate, expects, estimates, believes, goals or projects and similar expressions are intended to identify forward-looking statements. It is important to note that Chesapeake's actual results could differ materially from those projected by such forward-looking statements. Important factors that could cause actual results to differ materially from those projected in the forward-looking statements include, but are not limited to, the following: production variances from expectations, volatility of oil and gas prices, the need to develop and replace its reserves, the substantial capital expenditures required to fund its operations and acquisition strategy and the related need to fund such capital requirements through commercial banks and/or public securities markets, environmental risks, drilling and operating risks, risks related to exploration and development drilling, the uncertainty inherent in estimating future oil and gas production or reserves, uncertainty inherent in litigation, competition, government regulation, and the ability of the Company to implement its business strategy, including risks inherent in integrating acquisition operations into the Company's operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not Applicable

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

We have audited the accompanying consolidated balance sheets of Chesapeake Energy Corporation and its subsidiaries as of December 31, 1997 and as of June 30, 1997 and 1996, and the related consolidated statements of operations, stockholders' equity and cash flows for the six months ended December 31, 1997 and the years ended June 30, 1997 and 1996. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audits 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Chesapeake Energy Corporation and its subsidiaries as of December 31, 1997 and as of June 30, 1997 and 1996, and the consolidated results of their operations and their cash flows for the six months ended December 31, 1997 and the years ended June 30, 1997 and 1996 in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.

Oklahoma City, Oklahoma
March 20, 1998

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders
of Chesapeake Energy Corporation

In our opinion, the consolidated statements of operations, of cash flows and of stockholders' equity for the year ended June 30, 1995 present fairly, in all material respects, the results of operations and cash flows of Chesapeake Energy Corporation and its subsidiaries for the year ended June 30, 1995, in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with generally accepted auditing standards 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 audit provides a reasonable basis for the opinion expressed above. We have not audited the consolidated financial statements of Chesapeake Energy Corporation and its subsidiaries for any period subsequent to June 30, 1995.

PRICE WATERHOUSE LLP

Houston, Texas
September 20, 1995, except for the fourth paragraph of Note 9
which is as of October 9, 1997 and except for the earnings per share
information as described in Note 1, which is as of March 24, 1998

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 1997	June 30, 1997	June 30, 1996
	($ in thousands)		
CURRENT ASSETS:			
Cash and cash equivalents	$ 123,860	$ 124,017	$ 51,638
Short-term investments	12,570	104,485	—
Accounts receivable:			
Oil and gas sales	10,654	10,906	12,687
Oil and gas marketing sales	20,493	19,939	6,982
Joint interest and other, net of allowances of $691,000, $387,000 and $340,000, respectively	38,781	25,311	27,661
Related parties	4,246	7,401	2,884
Inventory	5,493	4,854	5,163
Other	1,624	692	2,158
Total Current Assets	217,721	297,605	109,173
PROPERTY AND EQUIPMENT:			
Oil and gas properties, at cost based on full cost accounting:			
Evaluated oil and gas properties	1,095,363	865,516	363,213
Unevaluated properties	125,155	128,505	165,441
Less: accumulated depreciation, depletion and amortization	(602,391)	(431,983)	(92,720)
	618,127	562,038	435,934
Other property and equipment	67,633	50,379	18,162
Less: accumulated depreciation and amortization	(6,573)	(5,051)	(2,922)
Total Property and Equipment	679,187	607,366	451,174
OTHER ASSETS	55,876	44,097	11,988
TOTAL ASSETS	$ 952,784	$ 949,068	$572,335

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 1997	June 30, 1997	June 30, 1996
CURRENT LIABILITIES:			
Notes payable and current maturities of long-term debt	$ —	$ 1,380	$ 6,755
Accounts payable	81,775	86,817	54,514
Accrued liabilities and other	42,733	28,701	14,062
Revenues and royalties due others	28,972	29,428	33,503
Total Current Liabilities	153,480	146,326	108,834
LONG-TERM DEBT, NET	508,992	508,950	268,431
REVENUES AND ROYALTIES DUE OTHERS	10,106	6,903	5,118
DEFERRED INCOME TAXES	—	—	12,185
CONTINGENCIES AND COMMITMENTS (NOTE 4)	—	—	—
STOCKHOLDERS' EQUITY:			
Preferred Stock, $.01 par value, 10,000,000 shares authorized; none issued	—	—	—
Common Stock, 250,000,000 shares authorized; par value of $.01, $.01 and $.05 at December 31, 1997, June 30, 1997 and 1996, respectively; 74,298,061, 70,276,975 and 60,159,826 shares issued and outstanding at December 31, 1997, June 30, 1997 and 1996, respectively	743	703	3,008
Paid-in capital	460,733	432,991	136,782
Accumulated earnings (deficit)	(181,270)	(146,805)	37,977
Total Stockholders' Equity	280,206	286,889	177,767
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 952,784	$ 949,068	$572,335

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 95,657	$ 192,920	$110,849	$56,983
Oil and gas marketing sales	58,241	76,172	28,428	—
Oil and gas service operations	—	—	6,314	8,836
Interest and other	78,966	11,223	3,831	1,524
Total Revenues	232,864	280,315	149,422	67,343
COSTS AND EXPENSES:				
Production expenses and taxes	10,094	15,107	8,303	4,256
Oil and gas marketing expenses	58,227	75,140	27,452	—
Oil and gas service operations	—	—	4,895	7,747
Impairment of oil and gas properties	110,000	236,000	—	—
Oil and gas depreciation, depletion and amortization	60,408	103,264	50,899	25,410
Depreciation and amortization of other assets	2,414	3,782	3,157	1,765
General and administrative	5,847	8,802	4,828	3,578
Interest and other	17,448	18,550	13,679	6,627
Total Costs and Expenses	264,438	460,645	113,213	49,383
INCOME (LOSS) BEFORE INCOME TAXES AND EXTRAORDINARY ITEM	(31,574)	(180,330)	36,209	17,960
PROVISION (BENEFIT) FOR INCOME TAXES	—	(3,573)	12,854	6,299
INCOME (LOSS) BEFORE EXTRAORDINARY ITEM	(31,574)	(176,757)	23,355	11,661
EXTRAORDINARY ITEM:				
Loss on early extinguishment of debt, net of applicable income tax of $3,804	—	(6,620)	—	—
NET INCOME (LOSS)	$(31,574)	$(183,377)	$ 23,355	$11,661
EARNINGS (LOSS) PER COMMON SHARE:				
EARNINGS (LOSS) PER COMMON SHARE — BASIC				
Income (loss) before extraordinary item	$ (0.45)	$ (2.69)	$ 0.43	$ 0.22
Extraordinary item	—	(0.10)	—	—
Net income (loss)	$ (0.45)	$ (2.79)	$ 0.43	$ 0.22
EARNINGS (LOSS) PER COMMON SHARE — ASSUMING DILUTION				
Income (loss) before extraordinary item	$ (0.45)	$ (2.69)	$ 0.40	$ 0.21
Extraordinary item	—	(0.10)	—	—
Net income (loss)	$ (0.45)	$ (2.79)	$ 0.40	$ 0.21
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (IN 000'S)				
Basic	70,835	65,767	54,564	52,624
Assuming Dilution	70,835	65,767	58,342	55,872

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ in thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:				
NET INCOME (LOSS)	$ (31,574)	$(183,377)	$ 23,355	$ 11,661
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO NET CASH PROVIDED BY OPERATING ACTIVITIES:				
Depreciation, depletion and amortization	62,028	105,591	52,768	26,628
Deferred taxes	—	(3,573)	12,854	6,299
Amortization of loan costs	794	1,455	1,288	548
Amortization of bond discount	41	217	563	567
Bad debt expense	40	299	114	308
Gain on sale of Bayard stock	(73,840)	—	—	—
Gain on sale of fixed assets	(209)	(1,593)	(2,511)	(108)
Impairment of oil and gas assets	110,000	236,000	—	—
Extraordinary loss	—	6,620	—	—
Equity in (earnings) losses from investments	592	(499)	—	—
CHANGES IN ASSETS AND LIABILITIES (NET OF ASSETS AND LIABILITIES ACQUIRED FROM ANSON PRODUCTION CORPORATION):				
(Increase) decrease in short-term investments	92,127	(102,858)	622	—
(Increase) decrease in accounts receivable	(7,173)	(19,987)	(3,524)	(22,510)
(Increase) decrease in inventory	(1,584)	(1,467)	78	(1,203)
(Increase) decrease in other current assets	(1,519)	1,466	(1,525)	614
Increase (decrease) in accounts payable, accrued liabilities and other	(11,044)	48,085	25,834	19,387
Increase (decrease) in current and non-current revenues and royalties due others	478	(2,290)	11,056	12,540
Cash provided by operating activities	139,157	84,089	120,972	54,731
CASH FLOWS FROM INVESTING ACTIVITIES:				
Exploration, development and acquisition of oil and gas properties	(189,755)	(468,462)	(342,045)	(117,831)
Proceeds from sale of oil and gas equipment, leasehold and other	2,503	3,095	6,167	11,953
Net proceeds from sale of Bayard stock	90,380	—	—	—
Repayment of note receivable	18,000	—	—	—
Other proceeds from sales	17	6,428	698	1,104
Long term loans made to third parties	—	(20,000)	—	—
Investment in oil field service company	(200)	(3,048)	—	—
Investment in gas marketing company, net of cash acquired	—	—	(363)	—
Other investments	(30,434)	(8,000)	—	—
Other property and equipment additions	(27,015)	(33,867)	(8,846)	(7,929)
Cash used in investing activities	(136,504)	(523,854)	(344,389)	(112,703)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from issuance of common stock	—	288,091	99,498	—
Proceeds from long-term borrowings	—	342,626	166,667	128,834
Payments on long-term borrowings	—	(119,581)	(48,634)	(32,370)
Dividends paid on common stock	(2,810)	—	—	—
Cash received from exercise of stock options	322	1,387	1,989	818
Other financing	(322)	(379)	—	—
Cash provided by (used in) financing activities	(2,810)	512,144	219,520	97,282
Net increase (decrease) in cash and cash equivalents	(157)	72,379	(3,897)	39,310
Cash and cash equivalents, beginning of period	124,017	51,638	55,535	16,225
Cash and cash equivalents, end of period	$ 123,860	$ 124,017	$ 51,638	$ 55,535
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION CASH PAYMENTS FOR:				
Interest, net of capitalized interest	$ 17,367	$ 12,919	$ 10,751	$ 4,914
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	$ (27,500)	$ —	$ —	$ —

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

Supplemental Schedule of Non-Cash Investing and Financing Activities:

The Company had a financing arrangement with a vendor to supply certain oil and gas equipment inventory. The total amounts owed at June 30, 1997, 1996 and 1995 were $1,380,000, $3,156,000 and $6,513,000, respectively. No cash consideration is exchanged for inventory under this financing arrangement until actual draws on the inventory are made.

In fiscal 1997, 1996 and 1995, the Company recognized income tax benefits of $4,808,000, $7,950,000 and $1,229,000, respectively, 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 $150 million of 7.875% Senior Notes and $150 million of 8.5% Senior Notes in March 1997 are net of $6.4 million in offering fees and expenses which were deducted from the actual cash received.

Proceeds from the issuances of $90 million of 10.5% Senior Notes in May 1995 and $120 million of 9.125% Senior Notes in April 1996 are net of $2.7 million and $3.9 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ in thousands)		
COMMON STOCK:				
Balance, beginning of period	$ 703	$ 3,008	$ 58	$ 51
Issuance of 8,972,000 shares of common stock	—	90	—	—
Issuance of 5,989,500 shares of common stock	—	—	299	—
Exercise of stock options and warrants	2	12	79	7
Issuance of 3,792,724 shares of common stock to AnSon Production Corporation	38	—	—	—
Change in par value	—	(2,407)	2,572	—
Balance, end of period	743	703	3,008	58
COMMON STOCK WARRANTS:				
Balance, beginning of period	—	—	—	5
Exercise of Common Stock Warrants	—	—	—	(5)
Balance, end of period	—	—	—	—
PAID-IN CAPITAL:				
Balance, beginning of period	432,991	136,782	30,295	28,243
Exercise of stock options and warrants	320	1,375	1,910	823
Issuance of common stock	27,459	301,593	105,516	—
Offering expenses and other	—	(13,974)	(6,317)	—
Cumulative exchange loss	(37)	—	—	—
Tax benefit from exercise of stock options	—	4,808	7,950	1,229
Change in par value	—	2,407	(2,572)	—
Balance, end of period	460,733	432,991	136,782	30,295
ACCUMULATED EARNINGS (DEFICIT):				
Balance, beginning of period	(146,805)	37,977	14,622	2,961
Net income (loss)	(31,574)	(183,377)	23,355	11,661
Dividends on common stock of $0.02 per share	(2,891)	(1,405)	—	—
Balance, end of period	(181,270)	(146,805)	37,977	14,622
TOTAL STOCKHOLDERS' EQUITY	$ 280,206	$ 286,889	$177,767	$44,975

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 a petroleum 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 Texas, Louisiana, Oklahoma, Montana, North Dakota, New Mexico and Canada.

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

Principles of Consolidation

The accompanying consolidated financial statements of Chesapeake Energy Corporation (the "Company") include the accounts of its wholly-owned subsidiaries Chesapeake Operating, Inc. ("COI"), Chesapeake Exploration Limited Partnership ("CEX"), a limited partnership, Chesapeake Louisiana, L.P. ("CLLP"), a limited partnership, Chesapeake Gas Development Corporation ("CGDC"), Chesapeake Energy Marketing, Inc. ("CEMI"), Chesapeake Canada Corporation ("CCC"), Chesapeake Energy Louisiana Corporation ("CELC"), Chesapeake Acquisition Corporation ("CAC"), Lindsay Oil Field Supply, Inc.("LOF"), Sander Trucking Company, Inc. ("STCO") and subsidiaries of those entities. As of June 30, 1997, CGDC had been merged into CEX, and LOF and STCO had been dissolved. 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. At December 31, 1997, the Company had an unrealized holding loss of $2.4 million included in interest and other revenue. At June 30, 1997, the Company had an unrealized holding loss of $0.6 million included in interest and other revenue. At June 30, 1996 the Company had no trading securities. 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. The Company's oil and gas reserves are estimated at least annually by independent petroleum engineers and quarterly by the Company's internal engineers. The average composite rates used for depreciation, depletion and amortization were $1.57 per equivalent Mcf in the six months ended December 31, 1997 and $1.31, $0.85 and $0.80 per equivalent Mcf in fiscal 1997, 1996 and 1995, respectively.

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, shall 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. At December 31, 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 $110 million. At June 30, 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 fourth quarter 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 is depreciated over the estimated useful lives of the assets, which range from five to seven years.

Capitalized Interest

During the six months ended December 31, 1997 and fiscal 1997, 1996 and 1995, interest of approximately $5,087,000, $12,935,000, $6,428,000 and $1,574,000 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.

Service Operations

Certain subsidiaries of the Company performed contract services on wells the Company operated as well as for third parties until June 30, 1996. Oil and gas service operations revenues and costs and expenses reflected in the accompanying consolidated statements of operations include amounts derived from certain of the contractual services provided. The Company's economic interest in its oil and gas properties was not affected by the performance of these contractual services and all intercompany profits have been eliminated.

On June 30, 1996, Peak USA Energy Services, Ltd., a limited partnership ("Peak"), was formed by Peak Oilfield Services Company (a joint venture between Cook Inlet Region, Inc. and Nabors Industries, Inc.) and the Company for the purpose of purchasing the Company's oilfield service assets and providing rig moving, transportation and related site construction services. The Company sold its service company assets to Peak for $6.4 million and simultaneously invested $2.5 million in exchange for a 33.3% partnership interest in Peak. This transaction resulted in recognition of a $1.8 million pre-tax gain during the fourth fiscal quarter of 1996 reported in Interest and other. A deferred gain from the sale of service company assets of $0.9 million was recorded as a reduction in the Company's investment in Peak and will be amortized to income over the estimated useful lives of the Peak assets. The Company's investment in Peak is accounted for using the equity method.

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

In February 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 128, Earnings Per Share ("SFAS 128"). 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 is effective for financial statements issued for periods ending after December 15, 1997 and requires restatement of all prior period earnings per share amounts. The Company has adopted SFAS 128 and has restated all prior periods presented.

SFAS 128 requires a reconciliation of the numerators and denominators of the basic and diluted EPS computations. For 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 8.3 million and 7.9 million shares of common stock at weighted average exercise prices of $5.49 and $7.09 were outstanding during 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 fiscal 1996 and 1995 is as follows:

	Income (Numerator)	Shares (Denominator)	Per-Share Amount
FOR THE YEAR ENDED JUNE 30, 1996:			
BASIC EPS			
Income available to common stockholders	$23,355	54,564	$0.43
EFFECT OF DILUTIVE SECURITIES			
Employee stock options	—	3,778	
DILUTED EPS			
Income available to common stockholders and assumed conversions	$23,355	58,342	$0.40
FOR THE YEAR ENDED JUNE 30, 1995:			
BASIC EPS			
Income available to common stockholders	$11,661	52,624	$0.22
EFFECT OF DILUTIVE SECURITIES			
Employee stock options	—	3,248	
DILUTED EPS			
Income available to common stockholders and assumed conversions	$11,661	$55,872	$0.21

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, 1997 and June 30, 1997 and 1996 were not material.

Hedging

The Company periodically uses certain instruments to hedge its exposure to price fluctuations on oil and natural gas transactions. Recognized gains and losses on hedge contracts are reported as a component of the related transaction. Results for hedging transactions are reflected in oil and gas sales to the extent related to the Company's oil and gas production, and in oil and gas marketing sales to the extent related to the Company's marketing activities (see Note 10).

Debt Issue Costs

Other assets include the costs associated with the issuance of the 10.5% Senior Notes on May 25, 1995, the 9.125% Senior Notes on April 9, 1996, and the 7.875% and 8.5% Senior Notes on March 17, 1997 (see Note 2). The remaining unamortized costs on these issuances of Senior Notes at December 31, 1997 totaled $11.6 million and are being amortized over the life of the Senior Notes.

Stock Options

In October 1995, the Financial Accounting Standards Board issued Statement No. 123 ("SFAS 123"), "Accounting for Stock Based Compensation". As permitted by SFAS 123, the Company has continued its previous method of accounting for stock compensation and adopted the disclosure requirements of this Statement in fiscal 1997.

Reclassifications

Certain reclassifications have been made to the consolidated financial statements for the years ended June 30, 1997, 1996 and 1995 to conform to the presentation used for the December 31, 1997 consolidated financial statements.

2. SENIOR NOTES

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.

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 price 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. The Company may also redeem at its option at any time on or prior to April 15, 1999 up to $42 million of the 9.125% Senior Notes at 109.125% of the principal amount thereof with the proceeds of an equity offering.

On May 25, 1995, the Company issued $90 million principal amount of 10.5% Senior Notes due 2002 ("10.5% Senior Notes"). The 10.5% Senior Notes are redeemable at the option of the Company at any time on or after June 1, 1999. The Company may also redeem at its option at any time on or prior to June 1, 1998 up to $30 million of the 10.5% Senior Notes at 110% of the principal amount thereof with the proceeds of an equity offering.

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 10.5% 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 10.5%, 9.125%, 7.875% and 8.5% 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 10.5% and 9.125% Senior Notes in the event of a change of control or certain asset sales.

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.

As of and for the six months ended December 31, 1997, the Guarantor Subsidiaries were COI, CEX, CLLP, CELC and CCC, and the Non-Guarantor Subsidiaries were CEMI, CAC and subsidiaries of those companies. As of and for the year ended June 30, 1997, the Guarantor Subsidiaries were COI, CEX, CLLP, CELC, and CGDC, and the Non-Guarantor Subsidiaries were CEMI and CCC. Prior to fiscal 1997, the Guarantor Subsidiaries were COI, CEX and two service company subsidiaries the assets of which were sold effective June 30, 1996, and the Non-Guarantor Subsidiaries were CGDC and CEMI (which was acquired in December 1995).

CONDENSED CONSOLIDATING BALANCE SHEET
As of December 31, 1997
($ In Thousands)

ASSETS

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ (589)	$ 13,999	$ 110,450	$ —	$ 123,860
Short-term investments	—	—	12,570	—	12,570
Accounts receivable	57,476	22,882	1,524	(7,708)	74,174
Inventory	4,918	575	—	—	5,493
Other	1,613	1	10	—	1,624
Total Current Assets	63,418	37,457	124,554	(7,708)	217,721
PROPERTY AND EQUIPMENT:					
Oil and gas properties	1,056,118	39,245	—	—	1,095,363
Unevaluated leasehold	125,155	—	—	—	125,155
Other property and equipment	51,868	343	15,422	—	67,633
Less: accumulated depreciation, depletion and amortization	(593,359)	(14,650)	(955)	—	(608,964)
	639,782	24,938	14,467	—	679,187
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	81,755	49,958	903,713	(1,035,426)	—
OTHER ASSETS	10,189	6,918	38,769	—	55,876
TOTAL ASSETS	$ 795,144	$119,271	$1,081,503	$(1,043,134)	$ 952,784

LIABILITIES AND STOCKHOLDERS' EQUITY

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ —	$ —	$ —	$ —	$ —
Accounts payable and other	104,259	29,649	27,280	(7,708)	153,480
Total Current Liabilities	104,259	29,649	27,280	(7,708)	153,480
LONG-TERM DEBT	—	—	508,992	—	508,992
REVENUES AND ROYALTIES DUE OTHERS	10,106	—	—	—	10,106
DEFERRED INCOME TAXES	—	—	—	—	—
INTERCOMPANY PAYABLES	853,958	2,959	—	(856,917)	—
STOCKHOLDERS' EQUITY:					
Common Stock	10	3	733	(3)	743
Other	(173,189)	86,660	544,498	(178,506)	279,463
	(173,179)	86,663	545,231	(178,509)	280,206
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 795,144	$119,271	$1,081,503	$(1,043,134)	$ 952,784

CONDENSED CONSOLIDATING BALANCE SHEET
As of June 30, 1997
($ In Thousands)

ASSETS

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ (6,534)	$ 4,363	$126,188	$ —	$ 124,017
Short-term investments	—	4,324	100,161	—	104,485
Accounts receivable	47,379	19,943	3,022	(6,787)	63,557
Inventory	4,795	59	—	—	4,854
Other	666	26	—	—	692
Total Current Assets	46,306	28,715	229,371	(6,787)	297,605
PROPERTY AND EQUIPMENT:					
Oil and gas properties	865,485	31	—	—	865,516
Unevaluated leasehold	128,519	(14)	—	—	128,505
Other property and equipment	33,486	1,904	14,989	—	50,379
Less: accumulated depreciation, depletion and amortization	(436,276)	—	(758)	—	(437,034)
	591,214	1,921	14,231	—	607,366
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	817	—	680,439	(681,256)	—
OTHER ASSETS	4,961	673	38,463	—	44,097
TOTAL ASSETS	$ 643,298	$31,309	$962,504	$(688,043)	$ 949,068

LIABILITIES AND STOCKHOLDERS' EQUITY

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 1,380	$ —	$ —	$ —	$ 1,380
Accounts payable and other	122,241	17,527	11,965	(6,787)	144,946
Total Current Liabilities	123,621	17,527	11,965	(6,787)	146,326
LONG-TERM DEBT	—	—	508,950	—	508,950
REVENUES AND ROYALTIES DUE OTHERS	6,903	—	—	—	6,903
DEFERRED INCOME TAXES	—	—	—	—	—
INTERCOMPANY PAYABLES	589,111	1,492	—	(590,603)	—
STOCKHOLDERS' EQUITY:					
Common Stock	11	1	693	(2)	703
Other	(76,348)	12,289	440,896	(90,651)	286,186
	(76,337)	12,290	441,589	(90,653)	286,889
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 643,298	$31,309	$962,504	$(688,043)	$ 949,068

CONDENSED CONSOLIDATING BALANCE SHEET
As of June 30, 1996
($ In Thousands)

ASSETS

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$ 4,061	$ 2,751	$ 44,826	$ —	$ 51,638
Accounts receivable	44,080	7,723	—	(1,589)	50,214
Inventory	4,947	216	—	—	5,163
Other	2,155	3	—	—	2,158
Total Current Assets	55,243	10,693	44,826	(1,589)	109,173
PROPERTY AND EQUIPMENT:					
Oil and gas properties	338,610	24,603	—	—	363,213
Unevaluated leasehold	165,441	—	—	—	165,441
Other property and equipment	9,608	61	8,493	—	18,162
Less: accumulated depreciation, depletion and amortization	(87,193)	(8,007)	(442)	—	(95,642)
	426,466	16,657	8,051	—	451,174
INVESTMENTS IN SUBSIDIARIES AND INTERCOMPANY ADVANCES	519,386	8,132	382,388	(909,906)	—
OTHER ASSETS	2,310	940	8,738	—	11,988
TOTAL ASSETS	$1,003,405	$ 36,422	$444,003	$(911,495)	$572,335

LIABILITIES AND STOCKHOLDERS' EQUITY

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
CURRENT LIABILITIES:					
Notes payable and current maturities of long-term debt	$ 3,846	$ 2,880	$ 29	$ —	$ 6,755
Accounts payable and other	91,069	7,339	5,260	(1,589)	102,079
Total Current Liabilities	94,915	10,219	5,289	(1,589)	108,834
LONG-TERM DEBT	2,113	10,020	256,298	—	268,431
REVENUES AND ROYALTIES DUE OTHERS	5,118	—	—	—	5,118
DEFERRED INCOME TAXES	23,950	1,335	(13,100)	—	12,185
INTERCOMPANY PAYABLES	824,307	8,182	73,647	(906,136)	—
STOCKHOLDERS' EQUITY:					
Common Stock	117	2	2,891	(2)	3,008
Other	52,885	6,664	118,978	(3,768)	174,759
	53,002	6,666	121,869	(3,770)	177,767
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$1,003,405	$ 36,422	$444,003	$(911,495)	$572,335

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
Interest and other	515	192	110,751	(32,492)	78,966
Total Revenues	93,899	103,080	110,751	(74,866)	232,864
COSTS AND EXPENSES:					
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
Interest	27,481	39	22,420	(32,492)	17,448
Total Costs & Expenses	199,125	116,651	23,528	(74,866)	264,438
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)
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
Interest and other	778	749	49,224	(39,528)	11,223
Total Revenues	192,081	146,691	49,224	(107,681)	280,315
COSTS AND EXPENSES:					
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 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
Interest	37,644	10	20,424	(39,528)	18,550
Total Costs & Expenses	400,480	144,304	23,542	(107,681)	460,645
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 OPERATIONS — (Continued)
($ In Thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
FOR THE YEAR ENDED JUNE 30, 1996:					
REVENUES:					
Oil and gas sales	$ 103,712	$ 6,884	$ —	$ 253	$ 110,849
Gas marketing sales	—	34,973	—	(6,545)	28,428
Oil and gas service operations	6,314	—	—	—	6,314
Interest and other	1,917	238	1,676	—	3,831
Total Revenues	111,943	42,095	1,676	(6,292)	149,422
COSTS AND EXPENSES:					
Production expenses and taxes	7,557	746	—	—	8,303
Gas marketing expenses	—	33,744	—	(6,292)	27,452
Oil and gas service operations	4,895	—	—	—	4,895
Oil and gas depreciation, depletion amortization	48,333	2,566	—	—	50,899
Other depreciation and amortization	1,924	73	1,160	—	3,157
General and administrative	3,683	496	649	—	4,828
Interest and other	508	711	12,460	—	13,679
Total Costs & Expenses	66,900	38,336	14,269	(6,292)	113,213
Income (loss) before income taxes	45,043	3,759	(12,593)	—	36,209
Income tax expense (benefit)	15,990	1,335	(4,471)	—	12,854
Net income (loss)	$ 29,053	$ 2,424	$ (8,122)	$ —	$ 23,355
FOR THE YEAR ENDED JUNE 30, 1995:					
REVENUES:					
Oil and gas sales	$ 55,417	$ 1,566	$ —	$ —	$ 56,983
Oil and gas service operations	8,836	—	—	—	8,836
Interest and other	1,394	—	130	—	1,524
Total Revenues	65,647	1,566	130	—	67,343
COSTS AND EXPENSES:					
Production expenses and taxes	4,045	211	—	—	4,256
Oil and gas service operations	7,747	—	—	—	7,747
Oil and gas depreciation, depletion amortization	24,775	635	—	—	25,410
Other depreciation and amortization	1,245	5	515	—	1,765
General and administrative	2,620	58	900	—	3,578
Interest and other	570	184	5,873	—	6,627
Total Costs & Expenses	41,002	1,093	7,288	—	49,383
Income (loss) before income taxes	24,645	473	(7,158)	—	17,960
Income tax expense (benefit)	8,639	165	(2,505)	—	6,299
Net Income (loss)	$ 16,006	$ 308	$ (4,653)	$ —	$ 11,661

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	(189,772)	17	—	—	(189,755)
Proceeds from sale of assets	2,520	—	—	—	2,520
Investment in service operations	(200)	—	—	—	(200)
Other investments	(26,472)	—	99,380	—	72,908
Other additions	(22,864)	1,340	(453)	—	(21,977)
	(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
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	(468,519)	57	—	—	(468,462)
Proceeds from sale of assets	9,523	—	—	—	9,523
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 CASH FLOWS — (Continued)
($ In Thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Company	Eliminations	Consolidated
FOR THE YEAR ENDED JUNE 30, 1996:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 126,868	$ 4,204	$ (10,100)	$ —	$ 120,972
CASH FLOWS FROM INVESTING ACTIVITIES					
Oil and gas properties	(341,246)	(6,099)	—	5,300	(342,045)
Proceeds from sales	12,165	—	—	(5,300)	6,865
Investment in gas marketing company	—	266	(629)	—	(363)
Other additions	(4,683)	(109)	(4,054)	—	(8,846)
	(333,764)	(5,942)	(4,683)	—	(344,389)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	40,350	10,300	116,017	—	166,667
Payments on borrowings	(45,397)	(3,200)	(37)	—	(48,634)
Exercise of stock options	—	—	1,989	—	1,989
Issuance of common stock	—	—	99,498	—	99,498
Intercompany advances, net	162,777	(2,616)	(160,161)	—	—
	157,730	4,484	57,306	—	219,520
Net increase (decrease) in cash and cash equivalents	(49,166)	2,746	42,523	—	(3,897)
Cash, beginning of period	53,227	5	2,303	—	55,535
Cash, end of period	$ 4,061	$ 2,751	$ 44,826	$ —	$ 51,638
FOR THE YEAR ENDED JUNE 30, 1995:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 60,049	$ 305	$ (4,692)	$ (931)	$ 54,731
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties	(113,722)	(4,109)	—	—	(117,831)
Proceeds from sales	24,557	—	—	(11,500)	13,057
Purchase of oil and gas properties	—	(11,500)	—	11,500	—
Other additions	(7,929)	—	—	—	(7,929)
	(97,094)	(15,609)	—	—	(112,703)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	30,034	11,500	87,300	—	128,834
Payments on borrowings	(32,032)	(700)	362	—	(32,370)
Intercompany advances, net	78,324	4,509	(83,764)	931	—
Other financing	—	—	818	—	818
	76,326	15,309	4,716	931	97,282
Net increase (decrease) in cash and cash equivalents	39,281	5	24	—	39,310
Cash, beginning of period	13,946	—	2,279	—	16,225
Cash, end of period	$ 53,227	$ 5	$ 2,303	$ —	$ 55,535

3. NOTES PAYABLE AND LONG-TERM DEBT

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

	December 31, 1997	June 30, 1997	June 30, 1996
	($ In Thousands)		
7.875% Senior Notes (see Note 2)	$150,000	$150,000	$ —
Discount on 7.875% Senior Notes	(106)	(115)	—
8.5% Senior Notes (see Note 2)	150,000	150,000	—
Discount on 8.5% Senior Notes	(833)	(862)	—
9.125% Senior Notes (see Note 2)	120,000	120,000	120,000
Discount on 9.125% Senior Notes	(69)	(73)	(81)
10.5% Senior Notes (see Note 2)	90,000	90,000	90,000
12% Senior Notes	—	—	47,500
Discount on 12% Senior Notes	—	—	(1,772)
Term note payable to Union Bank collateralized by CGDC, not guaranteed by the Company, variable interest at Union Bank's base rate (8.25% per annum at June 30, 1996), or at Eurodollar rate +1.875% collateralized by CGDC's producing oil and gas properties, payable in monthly installments through November 2002	—	—	12,900
Note payable to a vendor, collateralized by oil and gas tubulars, payments due 60 days from shipment of the tubulars	—	1,380	3,156
Note payable to a bank, variable interest at a referenced base rate +1.75% (10% per annum at June 30, 1996), collateralized by office buildings, payments due in monthly installments through May 1998	—	—	680
Notes payable to various entities to acquire oil service equipment, interest varies from 7% to 11% per annum, collateralized by equipment	—	—	1,212
Other collateralized	—	—	1,469
Other unsecured	—	—	122
Total notes payable and long-term debt	508,992	510,330	275,186
Less — Current maturities	—	(1,380)	(6,755)
Notes payable and long-term debt, net of current maturities	$508,992	$508,950	$268,431

The aggregate scheduled maturities of notes payable and long-term debt for the next five fiscal years ending December 31, 2002 and thereafter were as follows as of December 31, 1997 (in thousands of dollars):

1998	$ —
1999	—
2000	—
2001	—
2002	90,000
After 2002	418,992
	$508,992

In January 1998, the Company arranged a $500 million revolving credit facility with a group of commercial banks. The facility has an initial committed borrowing base of $200 million ($168 million until the acquisition of DLB Oil & Gas, Inc. (see Note 14) is consummated), of which $120 million was used to pay off bank debt assumed in the acquisition of Hugoton Energy Corporation (see Note 14) on March 10, 1998 and the remainder is anticipated to be used for other acquisitions. The borrowing base can be expanded as other acquisitions create collateral value. Borrowings under the facility are secured by CAC's pledge of its subsidiaries' capital stock and bear interest currently at a rate equal to the Eurodollar rate plus 1.5%.

During the quarter ended December 31, 1996, the Company exercised its covenant defeasance rights with respect to all of its outstanding $47.5 million of 12% Senior Notes due 2001. A combination of cash and non-callable U.S. Government Securities in the amount of $55.0 million was irrevocably deposited in trust to satisfy the Company's obligations, including accrued but unpaid interest through the date of defeasance of $1.3 million.

4. CONTINGENCIES AND COMMITMENTS

The Company and certain of its officers and directors are defendants in a consolidated class action suit alleging violations of the Securities Exchange Act of 1934. The plaintiffs assert that the defendants made material misrepresentations and failed to disclose material facts about the success of the Company's exploration efforts in the Louisiana Trend. As a result, the complaint alleges the price of the Company's common stock was artificially inflated from January 25, 1996 until June 27, 1997, when the Company issued a press release announcing disappointing drilling results in the Louisiana Trend and a full-cost ceiling writedown to be reflected in its June 30, 1997 financial statements. The plaintiffs further allege that certain of the named individual defendants sold common stock during the class period when they knew or should have known adverse nonpublic information. The plaintiffs seek a determination that the suit is a proper class action and damages in an unspecified amount, together with interest and costs of litigation, including attorneys' fees. The Company and the individual defendants believe that these claims are without merit, and intend to defend against them vigorously. No estimate of loss or range of estimate of loss, if any, can be made at this time.

Various purported class actions alleging violations of the Securities Act of 1933 and the Oklahoma Securities Act have been filed against the Company and others on behalf of investors who purchased common stock of Bayard Drilling Technologies, Inc. ("Bayard") in its initial public offering in November 1997. Total proceeds of the offering were $254 million, of which the Company received net proceeds of $90.2 million. 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. Plaintiffs assert that the Bayard prospectus contained material omissions and misstatements relating to (i) the Company's financial "hardships" and their significance on Bayard's business, (ii) increased costs associated with Bayard's growth strategy and (iii) undisclosed pending related-party transactions between Bayard and third parties other than the Company. The alleged defective disclosures are claimed to have resulted in a decline in Bayard's share price following the public offering. Each plaintiff seeks 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. The Company believes that these actions are without merit and intends to defend against them vigorously. No estimate of loss or range of estimate of loss, if any, can be made at this time.

In October 1996, Union Pacific Resources Company ("UPRC") sued the Company alleging infringement of a patent for a drilling method, tortious interference with confidentiality contracts between UPRC and certain of its former employees and misappropriation of proprietary information of UPRC. UPRC's claims against the Company are based on services provided to the Company by a third party vendor controlled by former UPRC employees. UPRC is seeking injunctive relief, damages of an unspecified amount, including actual, enhanced, consequential and punitive damages, interest, costs and attorneys' fees. The Company believes that it has meritorious defenses to UPRC's allegations and has requested the court to declare the UPRC patent invalid. The Company has also filed a motion to construe UPRC's patent claims and various motions for summary judgment. No estimate of a probable loss or range of estimate of a probable loss, if any, can be made at this time; however, in reports filed in the proceeding, experts for UPRC claim that damages could be as much as $18 million while Company experts state that the amount should not exceed $25,000, in each case based on a reasonable royalty.

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 the respective terms of the agreements in the event of termination of employment without cause. These agreements expire at various times from June 30, 1998 through June 30, 2000.

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.

As of December 31, 1997, the Company had guaranteed $1.8 million of debt owed by Peak.

On December 16, 1997, the Company acquired AnSon Production Corporation ("AnSon"), a privately owned oil and gas producer based in Oklahoma City. Consideration for this acquisition was approximately $43 million consisting of the issuance of 3,792,724 shares of Chesapeake's common stock and cash consideration in accordance with the terms of the merger agreement. The Company has accrued $15.5 million as the estimated cash payment which will be made during 1998.

The Company is in the process of acquiring various proved oil and gas reserves through mergers or through purchases of oil and gas properties. Upon the closing of each of these acquisitions, the Company will issue either cash or a combination of cash and Chesapeake common stock as consideration for the assets and liabilities being acquired. See Note 14 — Subsequent Events and Pending Transactions.

5. INCOME TAXES

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

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ In Thousands)		
Current	$ —	$ —	$ —	$ —
Deferred	—	(3,573)	12,854	6,299
Total	$ —	$(3,573)	$12,854	$6,299

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:

	Six Months Ending December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ In Thousands)		
Computed "expected" income tax provision (benefit)	$(11,051)	$(63,116)	$12,673	$6,286
Tax percentage depletion	(48)	(294)	(238)	(144)
Valuation allowance	13,818	64,116	—	—
State income taxes and other	(2,719)	(4,279)	419	157
	$ —	$ (3,573)	$12,854	$6,299

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:

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ In Thousands)		
Deferred tax liabilities:				
Acquisition, exploration and development costs and related depreciation, depletion and amortization	$(49,657)	$(49,831)	$(63,725)	$(31,220)
Deferred tax assets:				
Net operating loss carryforwards	126,485	112,889	50,776	23,414
Percentage depletion carryforward	1,106	1,058	764	526
	127,591	113,947	51,540	23,940
Net deferred tax asset (liability)	77,934	64,116	(12,185)	(7,280)
Less: Valuation allowance	(77,934)	(64,116)	—	—
Total deferred tax asset (liability)	$ —	$ —	$(12,185)	$ (7,280)

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 the Transition Period and the fourth quarter of fiscal 1997, the Company recorded a $110 million writedown and a $236 million writedown, respectively, related to the impairment of oil and gas properties. The writedowns 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, 1997 and June 30, 1997. Management believes it is more likely than not that the Company will generate future tax net operating losses for at least the next five years, based in part on the Company's continued drilling efforts. Therefore, the Company has recorded a valuation allowance equal to the net deferred tax asset.

At December 31, 1997, the Company had regular tax net operating loss carryforwards of approximately $337 million and alternative minimum tax net operating loss carryforwards of approximately $83 million. These loss carryforward amounts will expire during the years 2007 through 2012. The Company also had a percentage depletion carryforward of approximately $2.9 million at December 31, 1997, which is available to offset future 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 an Ownership Change. However, management believes this will not result in a significant limitation of the utilization 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, 1997 and June 30, 1997, 1996 and 1995, the Company had accounts receivable from such parties of $4.2 million, $7.4 million, $2.9 million and $4.4 million, respectively.

During the six months ended December 31, 1997 and during fiscal 1997, 1996 and 1995, the Company incurred legal expenses of $388,000, $207,000, $347,000 and $516,000, 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. 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 $418,000, $603,000, $187,000 and $95,000 to the plan during the six months ended December 31, 1997 and the fiscal years ended June 30, 1997, 1996 and 1995, respectively.

8. MAJOR CUSTOMERS

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

Six Months Ended December 31,		Amount ($ In Thousands)	Percent of Oil and Gas Sales
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%
1996	Aquila Southwest Pipeline Corporation	$41,900	38%
	GPM Gas Corporation	$28,700	26%
	Wickford Energy Marketing, L.C.	$18,500	17%
1995	Aquila Southwest Pipeline Corporation	$18,548	33%
	Wickford Energy Marketing, L.C.	$15,704	28%
	GPM Gas Corporation	$11,686	21%

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.

9. STOCKHOLDERS' EQUITY AND STOCK BASED COMPENSATION

On December 16, 1997, Chesapeake acquired AnSon, a privately owned oil and gas producer based in Oklahoma City. Consideration for this acquisition was approximately $43 million consisting of the issuance of 3,792,724 shares of Chesapeake 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 8,972,000 shares of Common Stock at a price of $33.63 per share, resulting in net proceeds to the Company of approximately $288.1 million.

On April 12, 1996, the Company completed a public offering of 5,989,500 shares of Common Stock at a price of $17.67 per share, resulting in net proceeds to the Company of approximately $99.4 million.

A 2-for-1 stock split of the Common Stock in December 1994, and in December 1996, and a 3-for-2 stock split of the Common Stock in December 1995 and in June 1996 have been given retroactive effect in these financial statements.

Stock Option Plans

Under the Company's 1992 Incentive Stock Option Plan (the "ISO Plan"), options to purchase Common Stock may be granted only to employees of the Company and its subsidiaries. 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. No options could be granted under the ISO Plan after December 16, 1994.

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. 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 may not be less than 75% 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 December 16, 2004 or under the 1996 Plan after October 14, 2006.

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 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 the six months ended December 31, 1997 and fiscal 1997 and 1996, respectively: interest rates (zero-coupon U.S. government issues with a remaining life equal to the expected term of the options) of 6.45%, 6.74% and 6.21%; dividend yields of 0.9%, 0.9% and 0.9%; volatility factors of the expected market price of the Company's common stock of .67, .60 and .60; and weighted-average expected life of the options of four 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:

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	Year Ended June 30, 1996
	($ In Thousands, Except Per Share Amounts)		
Net Income (Loss)			
As reported	$(31,574)	$(183,377)	$23,355
Pro forma	(35,084)	(190,160)	22,081
Earnings (Loss) per Share			
As reported	$ (0.45)	$ (2.79)	$ 0.40
Pro forma	(0.50)	(2.89)	0.38

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:

	Six Months Ended December 31, 1997 Options	Six Months Ended December 31, 1997 Weighted-Avg. Exercise Price
Outstanding Beginning of Period	7,903,659	$ 7.09
Granted	3,362,207	8.29
Exercised	(219,349)	3.13
Forfeited	(2,716,136)	13.87
Outstanding End of Period	8,330,381	5.49
Exercisable End of Period	3,838,869	
Shares Authorized for Future Grants	4,585,973	
Fair Value of Options Granted During the Period		$ 4.98

	Year Ended June 30, 1997		1996		1995	
	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price	Options	Weighted-Avg. Exercise Price
Outstanding Beginning of Year	7,602,884	$ 4.66	6,828,592	$1.97	5,033,340	$0.72
Granted	3,564,884	19.35	2,426,850	9.98	3,185,550	3.38
Exercised	(1,197,998)	1.95	(1,574,046)	1.31	(1,288,732)	0.67
Forfeited	(2,066,111)	22.26	(78,512)	2.61	(101,566)	0.92
Outstanding End of Year	7,903,659	7.09	7,602,884	4.66	6,828,592	1.97
Exercisable End of Year	3,323,824		2,974,386		2,489,742	
Shares Authorized for Future Grants	5,212,056		713,826		3,102,982	
Fair Value of Options Granted During the Year		$ 7.51		$4.84		N/A

The following table summarizes information about stock options outstanding at December 31, 1997:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding 12/31/97	Weighted-Avg. Remaining Contractual Life	Weighted-Avg. Exercise Price	Number Exercisable 12/31/97	Weighted-Avg. Exercise Price
$0.56 - $ 0.71	1,010,675	5.04	$ 0.61	1,010,675	$ 0.61
$0.78 - $ 1.33	562,500	4.47	$ 1.12	562,500	$ 1.12
$2.25 - $ 2.25	1,048,207	6.80	$ 2.25	687,982	$ 2.25
$2.43 - $ 4.92	408,689	6.92	$ 3.15	394,159	$ 3.08
$4.92 - $ 4.92	963,378	7.32	$ 4.92	382,618	$ 4.92
$5.67 - $ 5.67	1,138,724	7.67	$ 5.67	479,061	$ 5.67
$6.47 - $ 6.47	180,000	7.78	$ 6.47	180,000	$ 6.47
$7.31 - $ 7.31	997,606	9.64	$ 7.31	0	$ 0.00
$8.04 - $ 8.04	136,790	4.64	$ 8.04	0	$ 0.00
$8.75 - $30.63	1,883,812	9.45	$10.67	141,874	$24.80
$0.56 - $30.63	8,330,381	7.54	$ 5.49	3,838,869	$ 3.46

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 (or sale) and the option price. During the six months ended December 31, 1997 and fiscal 1997, 1996 and 1995, $0, $4,808,000, $7,950,000 and $1,229,000, respectively, were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to 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 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 (1) 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, (2) 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, (3) 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 (4) basis protection swaps, which are arrangements that guarantee the price differential of oil or gas from a specified delivery point or points. Results from 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 hedging transactions related to the Company's oil and gas production volumes or CEMI physical purchase or sale commitments.

As of December 31, 1997, the Company had the following oil swap arrangements for periods after December 1997:

Months	Volume (Bbls)	NYMEX-Index Strike Price (per Bbl)
January through June 1998	724,000	$19.82

The Company entered into oil swap arrangements to cancel the effect of the swaps at a price of $18.85 per Bbl.

As of December 31, 1997, the Company had the following gas swap arrangements for periods after December 1997:

Months	Volume (MMBtu)	Houston Ship Channel Index Strike Price (Per MMBtu)
April 1998	600,000	$2.300
May 1998	620,000	$2.215

The Company received $1.3 million as a premium for calls sold for January and February 1998 volumes of 2,480,000 MMBtu and 2,240,000 MMBtu, respectively. The January calls expired on December 31, 1997, the February calls expired on January 31, 1998, and the associated premiums will be recognized as income during the corresponding months of production.

The Company has also entered into the following collar transactions:

Months	Volume (MMBtu)	NYMEX Defined High Strike Price	NYMEX Defined Low Strike Price
March 1998	1,240,000	2.693	$2.33
April 1998	1,200,000	2.483	$2.11

These transactions require that the Company pay the counterparty if the NYMEX price exceeds the defined high strike price and that the counterparty pay the Company if the NYMEX price is less than the defined low strike price.

The Company entered into a curve lock for 4.9 Bcf of gas which allows the Company the option to hedge April 1999 through November 1999 gas based upon a negative $0.285 differential to December 1998 gas any time between the strike date and December 1998. A curve lock is a commodity swap arrangement that establishes, or hedges, a price differential between one commodity contract period and another. In markets where the forward curve is typically negatively sloped (prompt prices exceed deferred prices), an upward sloping price curve allows hedgers to lock in a deferred forward sale at a higher premium to a more prompt swap by a curve lock.

Gains or losses on crude oil and natural gas hedging transactions are recognized as price adjustments in the month of related production. The Company estimates that had all of the crude oil and natural gas swap agreements in effect for production periods beginning on or after January 1, 1998 terminated on December 31, 1997, based on the closing prices for NYMEX futures contracts as of that date, the Company would have received a net amount of approximately $1.1 million from the counterparty which would have represented the "fair value" at that date. These agreements were not terminated.

Periodically, CEMI enters into various hedging transactions designed to hedge against physical purchase 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.

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 investments in debt securities are 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. See Note 15 for the fair value of financial instruments included in noncurrent other assets at December 31, 1997. The Company estimates the fair value of its long-term, fixed-rate debt using quoted market prices. The Company's carrying amount for such debt at December 31, 1997 and June 30, 1997 and 1996 was $509.0 million, $508.9 million and $255.6 million, respectively, compared to approximate fair values of $517.0 million, $514.1 million and $261.2 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.

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, 1997	June 30, 1997	June 30, 1996
	($ In Thousands)		
Oil and gas properties:			
Proved	$1,095,363	$ 865,516	$363,213
Unproved	125,155	128,505	165,441
Total	1,220,518	994,021	528,654
Less accumulated depreciation, depletion and amortization	(602,391)	(431,983)	(92,720)
Net capitalized costs	$ 618,127	$ 562,038	$435,934

Unproved properties not subject to amortization at December 31, 1997, June 30, 1997 and 1996 consisted mainly of lease acquisition costs. The Company capitalized approximately $5,087,000, $12,935,000 and $6,428,000 of interest during the six months ended December 31, 1997 and the years ended June 30, 1997 and 1996 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:

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ In Thousands)		
Development costs	$120,628	$187,736	$138,188	$ 78,679
Exploration costs	40,534	136,473	39,410	14,129
Acquisition costs:				
Unproved properties	25,516	140,348	138,188	24,437
Proved properties	39,245	—	24,560	—
Capitalized internal costs	2,435	3,905	1,699	586
Proceeds from sale of leasehold, equipment and other	(1,861)	(3,095)	(6,167)	(11,953)
Total	$226,497	$465,367	$335,878	$105,878

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 the six months ended December 31, 1997 and for the years ended June 30, 1997, 1996 and 1995, respectively. 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.

	Six Months Ended December 31, 1997	Year Ended June 30, 1997	1996	1995
		($ In Thousands)		
Oil and gas sales	$ 95,657	$ 192,920	$110,849	$ 56,983
Production costs(a)	(10,094)	(15,107)	(8,303)	(4,256)
Impairment of oil and gas properties	(110,000)	(236,000)	—	—
Depletion and depreciation	(60,408)	(103,264)	(50,899)	(25,410)
Imputed income tax (provision) benefit(b)	31,817	60,544	(18,335)	(9,561)
Results of operations from oil and gas producing activities	$(53,028)	$(100,907)	$ 33,312	$ 17,756

(a) Production costs include lease operating expenses and production taxes.

(b) 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.

Capitalized costs, less accumulated amortization and related deferred income taxes, can not 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, 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 a writedown in the carrying value of oil and gas properties of $110 million. At June 30, 1997, capitalized costs of oil and gas properties also exceeded the estimated present value of future net revenues for 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.

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, 1997, Williamson Petroleum Consultants ("Williamson"), Porter Engineering Associates, Netherland, Sewell & Associates, Inc. and internal reservoir engineers evaluated approximately 46%, 48%, 4% and 2% of total proved oil and gas reserves, respectively. As of June 30, 1997, 1996 and 1995, the reserves evaluated by Williamson constituted approximately 50%, 99% and 99% of total proved reserves, respectively, 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, 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 the six months ended December 31, 1997 and for the years 1997, 1996 and 1995:

	December 31,		June 30,				June 30,	
	1997		1997		1996		1995	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved reserves, beginning of period	17,373	298,766	12,258	351,224	5,116	211,808	4,154	117,066
Extensions, discoveries and other additions	5,573	68,813	13,874	147,485	8,781	158,052	2,549	138,372
Revisions of previous estimate	(3,428)	(24,189)	(5,989)	(137,938)	(669)	12,987	(448)	(18,516)
Production	(1,857)	(27,327)	(2,770)	(62,005)	(1,413)	(51,710)	(1,139)	(25,114)
Sale of reserves-in-place	—	—	—	—	—	—	—	—
Purchase of reserves-in-place	565	23,055	—	—	443	20,087	—	—
Proved reserves, end of period	18,226	339,118	17,373	298,766	12,258	351,224	5,116	211,808
Proved developed reserves, end of period	10,087	178,082	7,324	151,879	3,648	144,721	1,973	77,764

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

On December 16, 1997, Chesapeake acquired AnSon, 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 revisions to the previous year's reserve estimates of approximately 5,989 MBbl and 137,938 MMcf, or approximately 174 Bcfe. The reserve revisions are 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 area of the Mid-Continent region, and to portions of the Austin Chalk Trend in Texas and Louisiana.

On April 30, 1996, the Company purchased interests in certain producing and non-producing oil and gas properties, including approximately 14,000 net acres of unevaluated leasehold, from Amerada Hess Corporation for $37.8 million. The properties are located in the Knox and Golden Trend fields of southern Oklahoma, most of which are operated by the Company. In fiscal 1996 the reserves acquired from Amerada Hess Corporation were included in both "Extensions, discoveries and other additions" and "Purchase of reserves in-place". The fiscal 1996 presentation has been restated in the current year to remove the acquired reserves from "Extensions, discoveries and other additions" with a corresponding offset to "Revisions of previous estimate". This revision resulted in no net change to total oil and gas reserves.

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.

Since December 31, 1997 oil and gas prices have declined, with oil prices reaching ten-year lows in March 1998. In addition, the Company has completed several acquisitions based on expectations of higher oil and gas prices than those currently being received. Based on NYMEX oil prices of $16.50 per Bbl and NYMEX gas prices of $2.35 per Mcf in effect on March 25, 1998, and estimates of the Company's proved reserves as of December 31, 1997 (pro forma for the acquisitions completed during the quarter ended March 31, 1998), the Company estimates it will incur an additional full cost ceiling writedown of between $175 million and $200 million as of March 31, 1998. If this occurs, the Company will incur a substantial loss for the first quarter of 1998 which would further reduce shareholders' equity.

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,	June 30,		
	1997	1997	1996	1995
		($ In Thousands)		
Future cash inflows	$1,100,807	$ 954,839	$1,101,642	$427,377
Future production costs	(223,030)	(190,604)	(168,974)	(75,927)
Future development costs	(158,387)	(152,281)	(137,068)	(76,543)
Future income tax provision	(108,027)	(104,183)	(135,543)	(51,789)
Future net cash flows	611,363	507,771	660,057	223,118
Less effect of a 10% discount factor	(181,253)	(92,273)	(198,646)	(63,207)
Standardized measure of discounted future net cash flows	$ 430,110	$ 415,498	$ 461,411	$159,911

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

	December 31, 1997	June 30, 1997	June 30, 1996	June 30, 1995
		($ In Thousands)		
Standardized measure, beginning of period	$415,498	$ 461,411	$ 159,911	$118,608
Sales of oil and gas produced, net of production costs	(85,563)	(177,813)	(102,546)	(52,727)
Net changes in prices and production costs	26,106	(99,234)	88,729	(24,807)
Extensions and discoveries, net of production and development costs	92,597	287,068	275,916	108,644
Changes in future development costs	(7,422)	(12,831)	(11,201)	3,406
Development costs incurred during the period that reduced future development costs	47,703	46,888	43,409	23,678
Revisions of previous quantity estimates	(62,655)	(199,738)	12,728	(21,595)
Purchase of reserves-in-place	25,236	—	29,641	—
Accretion of discount	43,739	54,702	18,814	14,126
Net change in income taxes	(14,510)	63,719	(57,382)	(5,586)
Changes in production rates and other	(50,619)	(8,674)	3,392	(3,836)
Standardized measure, end of period	$430,110	$ 415,498	$ 461,411	$159,911

12. TRANSITION PERIOD COMPARATIVE DATA

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

	Six Months Ended December 31,	
	1997	1996
		(Unaudited)
	($ In Thousands, Except Per Share Data)	
Revenues	$232,864	$122,702
Gross profit (loss) (a)	$(93,092)	$ 42,946
Income (loss) before income taxes and extraordinary item	$(31,574)	$ 39,246
Income taxes	—	14,325
Income (loss) before extraordinary item	(31,574)	24,921
Extraordinary item	—	(6,443)
Net income (loss)	$(31,574)	$ 18,478
Earnings per share — basic		
Income (loss) before extraordinary item	$ (0.45)	$ 0.40
Extraordinary item	—	(0.10)
Net income (loss)	$ (0.45)	$ 0.30
Earnings per share — assuming dilution		
Income (loss) before extraordinary item	$ (0.45)	$ 0.38
Extraordinary item	—	(0.10)
Net income (loss)	$ (0.45)	$ 0.28
Weighted average common shares outstanding (in 000's)		
Basic	70,835	61,985
Assuming dilution	70,835	66,300

(a) Total revenue excluding interest and other income, less total costs and expenses excluding interest and other expense.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for the six months ended December 31, 1997 and fiscal 1997 and 1996 are as follows ($ in thousands except per share data):

	Quarter Ended	
	September 30, 1997	December 31, 1997
Net sales	$72,532	$ 81,366
Gross profit (loss) (a)	8,210	(101,302)
Net Income (loss)	5,513	(37,087)
Net Income (loss) per share:		
Basic	.08	(.52)
Diluted	.08	(.52)

	Quarter Ended			
	September 30, 1996	December 31, 1996	March 31, 1997	June 30, 1997
Net sales	$48,937	$71,249	$79,809	$ 69,097
Gross profit (loss) (a)	14,889	28,057	25,737	(241,686)
Income (loss) before extraordinary item	8,204	16,717	16,105	(217,783)
Net income (loss)	8,204	10,274	15,928	(217,783)
Income (loss) per share before extraordinary item:				
Basic	.14	.26	.23	(3.12)
Diluted	.13	.25	.22	(3.12)

	Quarter Ended			
	September 30, 1996	December 31, 1996	March 31, 1997	June 30, 1997
Net sales	$21,988	$31,766	$44,145	$47,692
Gross profit(a)	6,368	11,368	14,741	13,580
Net income	2,915	5,459	7,623	7,358
Net income per share:				
Basic	.06	.10	.14	.12
Diluted	.05	.10	.13	.12

(a) Total revenue excluding interest and other income, less total costs and expenses excluding interest and other expense.

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, 1997 and at 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 $110 million and $236 million, respectively.

14. SUBSEQUENT EVENTS AND PENDING TRANSACTIONS

On October 22, 1997, the Company entered into an agreement to acquire by merger the Mid-Continent operations of DLB Oil & Gas, Inc. The Company will pay $17.5 million cash and will issue a total of five million shares of the Company's common stock as merger consideration to the shareholders of DLB. The closing of the DLB acquisition is expected to occur in late April 1998 and is subject to approval by DLB shareholders and other customary conditions. Certain shareholders of DLB, who collectively own approximately 77.7% of outstanding DLB common stock, have granted the Company an irrevocable proxy to vote such shares (or have executed a written consent) in favor of the merger.

On November 12, 1997, the Company entered into an agreement to acquire Hugoton Energy Corporation which was consummated on March 10, 1998. Each share of Hugoton common stock was converted into the right to receive 1.3 shares of Chesapeake common stock, requiring the Company to issue approximately 25.8 million shares of Chesapeake common stock (based on 19.8 million shares of Hugoton common stock outstanding as of February 6, 1998, which amount excludes shares issuable upon exercise of outstanding Hugoton options).

On January 30, 1998, the Company entered into an alliance with Ranger Oil Limited to jointly develop a 3.2 million acre area of mutual interest in the Helmet, Midwinter, and Peggo areas of northeastern British Columbia. In addition, the Company paid Ranger approximately $48 million. The transaction closed in January 1998 with an effective date of December 1, 1997.

In February 1998, the Company closed the purchase of the Mid-Continent properties of privately owned Enervest Management Company L.L.C. for $38 million.

On March 5, 1998, the Company entered into a definitive agreement to acquire 100% of the stock of MC Panhandle Corp., a wholly owned subsidiary of Occidental Petroleum Corporation. The Company has agreed to pay $105 million in cash for the estimated proved reserves in the West Panhandle Field in Carson, Gray, Hutchinson and Moore Counties of the Texas Panhandle. The effective date of the transaction is January 1, 1998 with closing scheduled for May 29, 1998.

15. ACQUISITIONS

On December 5, 1997, Chesapeake purchased from Pan East Petroleum Corporation ("Pan East"), a publicly-traded Canadian exploration and production company, 19.9% of Pan East's common stock for $22 million. The purpose of Chesapeake's investment is to assist Pan East in financing its share of the exploration, development and acquisition activities under a joint venture whereby Chesapeake has the right to participate as a non-operator with up to a 50% interest in all drilling activities and acquisitions made by Pan East during the two years ending December 31, 1999. The Company will account for its investment in Pan East using the equity method. Based upon the closing price of Pan East's common stock at December 31, 1997, the market value of Chesapeake's investment in Pan East was $12.6 million.

On December 16, 1997, the Company acquired AnSon, a privately owned oil and gas producer based in Oklahoma City. Consideration for this acquisition was approximately $43 million consisting of the issuance of 3,792,724 shares of Chesapeake's common stock and cash consideration in accordance with the terms of the merger agreement. The Company has accrued $15.5 million as the estimated cash payment which will be made during 1998.

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

Effective July 1, 1996, Price Waterhouse LLP sold its Oklahoma City practice to Coopers & Lybrand L.L.P. and resigned as the Company's independent accountants. The Company's decision to change independent accountants and retain Coopers & Lybrand L.L.P. was approved by the Audit Committee of the Board of Directors and by the Board of Directors. During the period Price Waterhouse LLP was engaged by the Company, Price Waterhouse LLP did not issue any report on the Company's financial statements containing an adverse opinion, disclaimer of opinion, or qualification. There were no disagreements between the Company and Price Waterhouse LLP on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, nor were there any reportable events.

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 30, 1998.

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 30, 1998.

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 30, 1998.

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 30, 1998.

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. No financial statement schedules are filed with this report as no 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.
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, its subsidiaries signatory thereto 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 registration statement on Form S-4 (No. 333-24995).
4.1.1*	— First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998, to Indenture filed as Exhibit 4.1.
4.2	— Indenture dated as of March 15, 1997 among the Registrant, as issuer, its subsidiaries signatory thereto, 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).
4.2.1*	— First Supplemental Indenture dated December 17, 1997 and Second Supplemental Indenture dated February 16, 1998 to Indenture filed as Exhibit 4.2.
4.3	— Indenture dated as of May 15, 1995 among Chesapeake Energy Corporation, its subsidiaries signatory thereto as Subsidiary Guarantors and United States Trust Company of New York, as Trustee, with respect to 10.5% Senior Notes due 2002. Incorporated herein by reference to Exhibit 4.3 to Registrant's registration statement on Form S-4 (No. 33-93718).
4.3.1*	— First Supplemental Indenture dated December 30, 1996 and Second Supplemental Indenture dated December 17, 1997 filed as Exhibit 4.3.

Exhibit Number	Description
4.4	— Indenture dated April 1, 1996 among Chesapeake Energy Corporation, 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 Registration Statement (No. 333-1588)
4.4.1*	— First Supplemental Indenture dated December 30, 1996 and Second Supplemental Indenture dated December 17, 1997, to Indenture filed as Exhibit 4.4.
4.5	— Agreement to furnish copies of unfiled long-term debt instruments.
4.6*	— Credit Agreement dated March 9, 1998 between Chesapeake Acquisition Corporation and Chesapeake Mid-Continent Corp., as Borrowers, Chesapeake Merger Corp., Chesapeake Acquisition Corp., Chesapeake Columbia Corp., Mid-Continent Gas Pipeline Company, and AnSon Gas Marketing as Initial Guarantors, Union Bank of California, N.A., as Agent and Certain Financial Institutions, as Lenders.
4.8	— Stock Registration Agreement dated May 21, 1992 between Chesapeake Energy Corporation and various lenders, as amended by First Amendment thereto dated May 26, 1992. Incorporated herein by reference to Exhibits 10.26.1 and 10.26.2 to Registrant's registration statement on Form S-1 (No. 33-55600).
4.9	— Registration Rights Agreement dated October 22, 1997 as amended by Amendment No. 1 dated December 22, 1997 between Chesapeake Energy Corporation and Charles E. Davidson. Incorporated herein by reference to Exhibits 4.9 and 4.10 to Registrant's registration statement on Form S-4 (No. 333-48735).
4.10	— Registration Rights Agreement between Chesapeake Energy Corporation and certain former shareholders of Hugoton Energy Corporation. Incorporated herein by reference to Exhibit 4.11 to Registrant's registration statement on Form S-4 Registration Statement (No. 333-48735).
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.
10.1.4.1	— Amendment to the Chesapeake Energy Corporation 1996 Stock Option Plan. Incorporated herein by reference to Exhibit 10.1.4.1 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.1†	— Employment Agreement dated as of July 1, 1997 between Aubrey K. McClendon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.1 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
10.2.2†	— Employment Agreement dated as of July 1, 1997 between Tom L. Ward and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.

Exhibit Number	Description
10.2.3†	— Employment Agreement dated as of July 1, 1997 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 June 30, 1997.
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.
10.2.7†	— Employment Agreement dated as of July 1, 1997 between Ronald A. Lefaive and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 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.
10.3†	— 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).
10.9	— Indemnity and Stock Registration Agreement, as amended by First Amendment (Revised) thereto, dated as of February 12, 1993, and as amended by Second Amendment thereto dated as of October 20, 1995, among Chesapeake Energy Corporation, Chesapeake Operating, Inc., Chesapeake Investments, TLW Investments, Inc., et al. Incorporated herein by reference to Exhibit 10.35 to Registrant's annual report on Form 10-K for the year ended June 30, 1993 and Exhibit 10.4.1 to Registrant's quarterly report on Form 10-Q for the quarter ended December 31, 1995.
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. Incorporated herein by reference to Exhibit 10.11 to Registrant's annual report on Form 10-K for the year ended June 30, 1997.
21*	— Subsidiaries of Registrant
23.1*	— Consent of Coopers & Lybrand L.L.P.
23.2*	— Consent of Price Waterhouse LLP
23.3*	— Consent of Williamson Petroleum Consultants, Inc.

Exhibit Number	Description
23.4*	— Consent of Netherland, Sewell & Associates, Inc.
23.5*	— Consent of Porter Engineering Associates
27*	— Financial Data Schedule

* Filed herewith.

† Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K

During the quarter ended December 31, 1997, the Company filed the following Current Reports on Form 8-K dated

October 1, 1997 announcing the declaration of a quarterly dividend.

October 31, 1997 announcing the acquisition of DLB Oil & Gas, Inc. and AnSon Production Corporation, and completion of Masters Creek wells.

November 5, 1997 announcing expected proceeds from the initial public offering of Bayard Drilling Technologies, Inc.

November 6, 1997 reporting fiscal 1998 first quarter results, $74 million profit from Bayard initial public offering, new Louisiana Trend completions, and change in fiscal year end.

November 20, 1997 announcing the change of its fiscal year end to December 31 and that a transition report on Form 10-K will be filed.

December 11, 1997 announced the successful completion of a well located in Pointe Coupee Parish, Louisiana.

December 24, 1997 announcing the declaration of a quarterly cash dividend on the Company's $0.01 par value common stock.

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

Date: March 31, 1998

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman of the Board and
Chief Executive Officer

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 31, 1998
/s/ TOM L. WARD Tom L. Ward	President, Chief Operating Officer and Director (Principal Executive Officer)	March 31, 1998
/s/ MARCUS C. ROWLAND Marcus C. Rowland	Senior Vice President Finance and Chief Financial Officer (Principal Financial Officer)	March 31, 1998
/s/ RONALD A. LEFAIVE Ronald A. Lefaive	Controller (Principal Accounting Officer	March 31, 1998
/s/ EDGAR F. HEIZER, JR. Edgar F. Heizer, Jr.	Director	March 31, 1998
/s/ BREENE M. KERR Breene M. Kerr	Director	March 31, 1998
/s/ SHANNON T. SELF Shannon T. Self	Director	March 31, 1998
/s/ FREDERICK B. WHITTEMORE Frederick B. Whittemore	Director	March 31, 1998
/s/ WALTER C. WILSON Walter C. Wilson	Director	March 31, 1998

Corporate Information

Stock Data	High	Low	Last
Fiscal 1995		*(in $)*	
First Quarter	2.39	0.86	2.36
Second Quarter	3.67	2.14	3.50
Third Quarter	4.84	2.22	4.72
Fourth Quarter	6.59	4.67	5.72
Fiscal 1996			
First Quarter	7.22	4.53	7.03
Second Quarter	11.09	6.28	11.09
Third Quarter	16.50	10.79	15.42
Fourth Quarter	29.96	16.04	29.96
Fiscal 1997			
First Quarter	35.13	20.81	31.31
Second Quarter	34.44	24.94	27.82
Third Quarter	31.38	19.38	20.88
Fourth Quarter	23.50	8.94	9.94
Transition Period Ended Dec. 31, 1997			
First Quarter	11.50	6.31	11.38
Second Quarter	11.75	7.00	7.56

Stock Split History

December 1994; 2-for-1
December 1995; 3-for-2
June 1996; 3-for-2
December 1996; 2-for-1

Trustees for the Company's Senior Notes

United States Trust Company
of New York
114 West 47th Street
New York, New York 10036

Internet Address

Company financial information, public disclosures and other information is available at Chesapeake's web site www.chesapeake-energy.com or by contacting Thomas S. Price, Jr. at the corporate office by calling (405) 848-8000, extension 257. E-mail requests may be directed to TPrice@chesapeake-energy.com.

Common Stock

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange under the symbol CHK. As of March 31, 1998, there were approximately 27,000 beneficial owners of the common stock.

Dividends

The Company initiated a quarterly dividend with the payment of $0.02 per common share on July 15, 1997. 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.

Corporate Headquarters

6100 North Western Avenue
Oklahoma City,
Oklahoma 73118
(405) 848-8000

Independent Public Accountants

Coopers & Lybrand L.L.P.
15 North Robinson, Suite 400
Oklahoma City, Oklahoma 73102
(405) 236-5800

Stock Transfer Agent and Registrar

UMB Bank, N.A.
928 Grand Blvd.
Kansas City, Missouri 64106
(816) 860-7760

Communication concerning the transfer of shares, lost certificates, duplicate mailings or change of address notifications should be directed to the transfer agent.

Forward Looking Statements

The information contained in this annual report includes certain forward-looking statements. When used in this document, the words "potential", "budgeted", "anticipate", "expect", "believe", "goals", "objectives", "projects", and similar expressions are intended to identify forward-looking statements. It is important to note that Chesapeake's actual results could differ materially from those projected by such forward-looking statements. Important factors that could cause actual results to differ materially from those projected in the forward-looking statements include, but are not limited to, the following: production variances from expectations, risks related to exploration and development drilling outcomes, uncertainties about estimates of reserves, volatility of oil and natural gas prices, the need to develop and replace reserves, the substantial capital expenditures required to fund its operations, the risk that aforementioned and subsequent acquisitions will fail to produce expected unit cost reductions and increase commercial oil and gas production and reserves, environmental risks, drilling and operating risks, competition, government regulation, and the ability of the company to implement its revised business strategy. Chesapeake's actual results could also differ materially due to risks associated with the integration of its business and operations with those various companies that it has acquired in a relatively short timeframe. These risks include, but are not limited to, the risk that the aforememtioned and subsequent acquistion will fail to produce expected efficiencies, unit cost reductions and increases in commercial oil and gas production and reserves. These and other risks are described in the company's documents and reports that are available from the United States Securities and Exchange Commission, including the report filed on Form 10-K for the Transition Period from July 1, 1997 to December 31, 1997.

DESIGN: Aspen Marketing + Design Inc., Aspen, Colorado

CHESAPEAKE ENERGY CORPORATION

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Oklahoma City, Oklahoma 73118
www.chesapeake-energy.com