Chesapeake

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Chesapeake Energy Corporation

1995 Annual Report

FISCAL YEAR ENDED JUNE 30,	**1995**	1994	1993	1992	1991
INCOME DATA ($ IN THOUSANDS, EXCEPT PER SHARE DATA)					
Oil and gas sales	**$ 56,983**	$ 22,404	$ 11,602	$ 10,520	$ 4,334
Service operations and other	**10,360**	7,420	6,406	8,198	2,109
Total revenues	**67,343**	29,824	18,008	18,718	6,443
Production expenses	**4,256**	3,647	2,890	2,103	760
Oil and gas property depreciation, depletion and amortization	**25,410**	8,141	4,184	2,910	1,585
Other depreciation and amortization	**1,765**	1,871	557	974	351
Service operations	**7,747**	5,199	3,653	4,113	606
General and administrative	**3,578**	3,135	3,620	3,314	2,119
Interest and other	**6,627**	2,676	2,282	2,577	317
Provision for legal and other settlements	**—**	—	1,286	—	—
Total costs and expenses	**49,383**	24,669	18,472	15,991	5,738
Income (loss) before income taxes	**17,960**	5,155	(464)	2,727	705
Income tax expense (benefit)	**6,299**	1,250	(99)	1,337	243
Net income (loss)	**11,661**	3,905	(365)	1,390	462
Earnings (loss) per share	**$ 0.94**	$ 0.36	$ (0.10)	$ 0.22	$ 0.07
Weighted average shares outstanding	**12,416**	10,720	7,456	6,202	6,202
PROPERTY DATA ($ IN THOUSANDS)					
Oil reserves (MBbls)	**5,116**	4,154	9,622	11,147	3,212
Gas reserves (MMcf)	**211,808**	117,066	79,763	68,618	17,334
Reserves in equivalent thousand barrels	**40,417**	23,665	22,915	22,583	6,101
Reserves in equivalent million cubic feet	**242,505**	141,992	137,495	135,500	36,606
Future net revenues discounted at 10% (before tax)	**$188,137**	$ 141,249	$141,665	$162,713*	$27,812
Oil production (MBbls)	**1,139**	537	276	374	163
Gas production (MMcf)	**25,114**	6,927	2,677	1,252	646
Production in equivalent thousand barrels	**5,325**	1,692	722	583	271
Production in equivalent million cubic feet	**31,947**	10,152	4,333	3,496	1,624
Average oil price (per Bbl)	**$ 17.36**	$ 15.09	$ 20.20	$ 21.85	$ 20.15
Average gas price (Mcf)	**$ 1.48**	$ 2.06	$ 2.25	$ 1.88	$ 1.59
Average gas equivalent price (per Mcfe)	**$ 1.78**	$ 2.21	$ 2.68	$ 3.01	$ 2.67

*As of October 1, 1992

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Who We Are

Chesapeake Energy Corporation is one of the fastest growing independent oil and natural gas exploration companies in the U. S. We are headquartered in Oklahoma City and our common stock is traded on the New York Stock Exchange under the symbol CHK.

What We Do

Chesapeake is one of the energy industry's leaders in enhanced seismic and advanced-technology drilling and well completion techniques. Our expertise with the drillbit helped generate the highest return to shareholders in the independent energy sector in fiscal 1995. Chesapeake focuses its efforts geographically in the southwestern U. S. where its inventory of 500 undrilled locations provide a three-year inventory of growth opportunities.

What We Have Accomplished

Since incorporation in 1989, Chesapeake has:

- Increased annual earnings to $12 million
- Increased operating cash flow to $45 million
- Increased annual oil and gas production to 32 Bcfe
- Increased proved reserves to 242 Bcfe

What Is Ahead For Chesapeake

In fiscal 1996 and beyond, Chesapeake's shareholders should benefit from the company's:

- Growth through the drillbit business strategy
- Large inventory of future drilling opportunities
- Advanced technological expertise in focused operating areas
- Superior operating margins from effective cost control
- Close alignment of shareholder and management interests

Through your investment in Chesapeake Energy Corporation, you have expressed confidence in Chesapeake's management and our strategy for continuing the growth of the company's reserves, production, cash flow, and earnings. More importantly, we understand that you expect your investment with us to increase in value. Therefore, we are pleased to report that in fiscal 1995, Chesapeake generated a 563% increase in shareholder value - the highest among all companies in the independent energy sector. This was achieved despite a 20% decline in natural gas equivalent prices during the fiscal year.

A key feature distinguishing Chesapeake from its peers has been its ability to produce superior returns to shareholders during periods of flat to lower commodity prices. We have built Chesapeake not just to survive these periods, but to grow and prosper in adverse environments. Our goal has been to create a new model for success as an independent energy producer by building on Chesapeake's competitive advantages described below.

Chesapeake's competitive advantages include:

- Growth through the drillbit business strategy;
- Large inventory of future drilling opportunities;
- Advanced technological expertise in focused operating areas;
- Superior operating margin from effective cost control, and;
- Close alignment of shareholder and management interests.

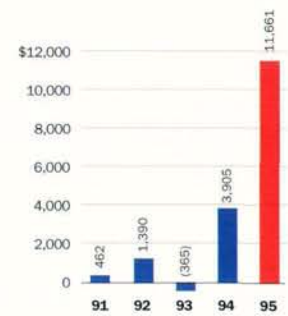
Before explaining why we believe these competitive advantages can continue to generate meaningful returns to our shareholders, we would like to highlight our operating and financial results for fiscal 1995.

1995's Achievements

During the year, Chesapeake:

- Increased oil and natural gas production 215% to 32 Bcfe.
- Increased total revenues 126% to $67.3 million.
- Increased earnings 200% to $11.7 million and earnings per share 161% to $0.94.
- Increased operating cash flow 198% to $45.1 million.
- Reduced operating costs (DD&A, lease operating expenses, production taxes, and G&A) 30% to $1.04 per Mcfe.
- Increased capital resources through a $90 million senior note offering and expanded bank credit facilities.

EARNINGS GROWTH
($ in thousands)



Chesapeake's earnings have increased by a compound growth rate of 90%...

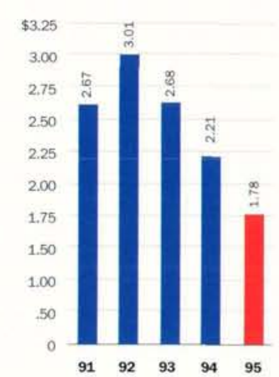
COMPETITIVE ADVANTAGES

To succeed in any industry, a company must have certain core competencies which provide distinct competitive advantages. This is especially true in the independent energy sector where more than 200 major and independent public companies compete to find, develop, and produce oil and natural gas reserves. We believe Chesapeake's five competitive advantages help explain how the company has thrived during this challenging period in the energy industry.

GROWTH THROUGH THE DRILLBIT

We have chosen to build Chesapeake through our expertise with the drillbit rather than by acquiring other companies' producing properties. We believe this strategy makes Chesapeake fundamentally different and stronger than most independent energy companies for three reasons.

AVERAGE OIL & GAS PRICES
($ per Mcfe)



... despite a 33% commodity price decline.

First, this strategy enables Chesapeake to capture more upside potential from drilling new wells. In the company's project areas, new wells can develop reserves with a value of up to five times the cost of drilling such wells. We accomplish this result by integrating enhanced seismic information with our drilling and completion expertise to develop new reservoirs. Our expertise with new exploration technologies greatly reduces geological risk while earning attractive returns even with today's low commodity prices.

Secondly, because most major oil and natural gas producers have significantly reduced domestic exploration efforts and many independent producers have focused on acquiring producing properties, there is less competition for good exploration ideas. With less competition, Chesapeake has a greater opportunity to leverage its exploration expertise into new areas that have the potential to significantly increase the company's value.

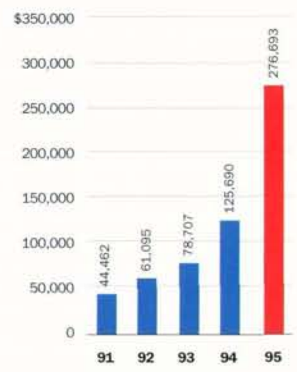
The third reason for Chesapeake's growth through the drillbit strategy is the efficiency created from owning new wells. Just as in operating a new car or factory, operating a newly drilled well is less expensive than operating an older well. Consequently, the company's production and administrative costs per unit of production are the lowest among its peers. Chesapeake therefore has more cash flow available per unit of production to reinvest in its drilling program, providing funding to continue growing the company's oil and natural gas reserves.

The success of this growth through the drillbit strategy is most evident in Chesapeake's oil and natural gas production growth. In the fourth quarter of fiscal 1993, Chesapeake's first full quarter as a public company, the company produced 1.1 Bcfe. By the fourth quarter of fiscal 1995, just two years later, Chesapeake's production increased to 11.9 Bcfe, an increase of almost 1,000%.

The company's creativity in identifying attractive geological opportunities, its technological expertise, and its financial resources have enabled Chesapeake, at the end of fiscal 1995 to be the third most active driller onshore in the U.S., ranking behind two much larger companies, Amoco and Union Pacific Resources.

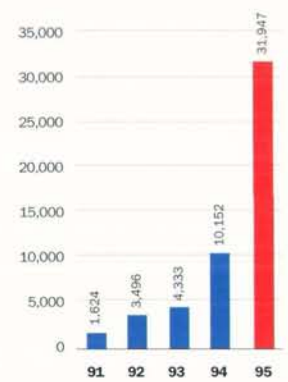
Also at the end of fiscal 1995, Chesapeake ranked first in average depth drilled per well (almost 15,000 feet). By drilling deeper into less extensively explored reservoirs, Chesapeake has a greater possibility of discovering large amounts of previously undiscovered or undeveloped oil and natural gas reserves. These prolific deposits of hydrocarbons are now within the company's reach due to technological advances in seismic and drilling and completion techniques.

ASSET GROWTH 100% THROUGH THE DRILLBIT
($ in thousands)



Chesapeake's assets have grown at a compound rate of 44%...

OIL & GAS PRODUCTION GROWTH
(in MMcfe)



... fueled by a compound production growth rate of 81%.

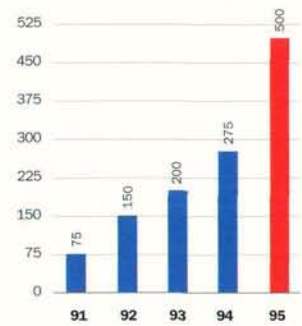
Three-Year Inventory of Drillsites

A leading indicator of an energy company's potential for future success is the size and quality of its inventory of future drilling projects. Chesapeake's three-year inventory of undrilled locations is our second competitive advantage and provides a strong foundation for our continued reserve and production growth.

The greatest challenge facing all energy producers is the need to replace the oil and natural gas reserves that deplete through daily oil and natural gas production. Similarly, the greatest challenge facing energy investors is the need to identify companies that can continue to grow their reserves and production. Rather than requiring an investor to speculate as to how Chesapeake might replace its depleting reserves with unspecified drilling or future property acquisitions, we have indentified 500 future drillsites on Chesapeake's existing leasehold.

This inventory consists of undrilled locations in the Navasota River, Independence, Knox, Masters Creek, Sholem Alechem, and Arkoma Jackfork project areas. We believe these future drilling opportunities have the potential to more than double Chesapeake's current reserves of oil and natural gas. The common theme linking these projects is Chesapeake's geological focus on unconventional reservoirs. The company has developed all of these projects during the past two years and is now working on several new project areas that have the potential to produce new discoveries in fiscal 1997 and beyond.

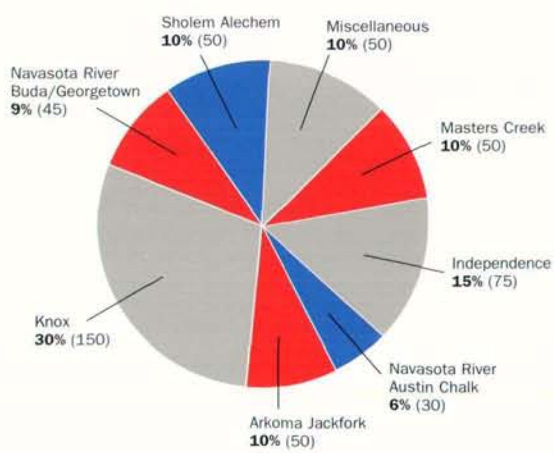
Undrilled Location Inventory



Chesapeake's prospect inventory provides substantial future growth opportunities.

Chesapeake Undrilled Locations

Cheaspeake's operations are diversified in seven major operating areas.



Technological Leadership

The increasing rate of technological change in such areas as horizontal drilling, 3-dimensional seismic, and deep fracture stimulation have enabled technically sophisticated companies such as Chesapeake to identify and develop new oil and natural gas reserves more profitably than at any time during the past 20 years. Although Chesapeake has distinguished itself in each of these new technologies, Chesapeake's leadership in horizontal drilling is particularly important. During fiscal 1995, Chesapeake drilled 61 horizontal wells and has drilled 230 horizontal wells since 1990. The company's expertise in horizontal drilling provides lower costs per foot of horizontal wellbore drilled and the potential for recovery of more reserves per dollar invested, both of which result in lower finding costs and higher operating margins.

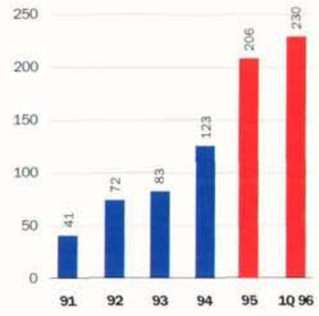
The talent of Chesapeake's landmen, geologists, and engineers, the company's strong relationships with the vendors who design and manufacture horizontal equipment, and our willingness to experiment with new ideas have enabled Chesapeake to drill increasingly deeper horizontal wells and thereby expand the boundaries of our fields. For example, in just the past year, significant improvements in measurement-while-drilling and logging-while-drilling tools, downhole motors, and drillbit technology have contributed to Chesapeake's extension of the downdip limit in Giddings from 13,000 feet to almost 15,000 feet.

The continued extension of this limit is important because as horizontal drilling technology improves, the number of prospective drillsites on Chesapeake's 350,000 gross acre leasehold inventory in Texas and Louisiana continues to increase. Specifically, for every 1,000 feet deeper the company can drill, up to 50 additional drillsites become prospective. Chesapeake's deeper drilling expertise should also enable the company to extend its downdip Giddings success into the potentially prolific Leesville and Masters Creek areas of Louisiana.

Chesapeake has also helped advance the technology of drilling multiple horizontal laterals from a single vertical wellbore. Drilling two or more horizontal laterals enables Chesapeake to develop its reserves by drilling fewer wells and thereby more efficiently using the company's capital. In the Independence area of the Giddings Field, Chesapeake is drilling its first quadrilateral well. This well has been designed to simultaneously produce reserves from both the Austin Chalk and Georgetown formations by drilling four horizontal laterals from one vertical wellbore. We anticipate a cost savings of 50% compared to drilling four single lateral horizontal wells.

Horizontal Wells Drilled

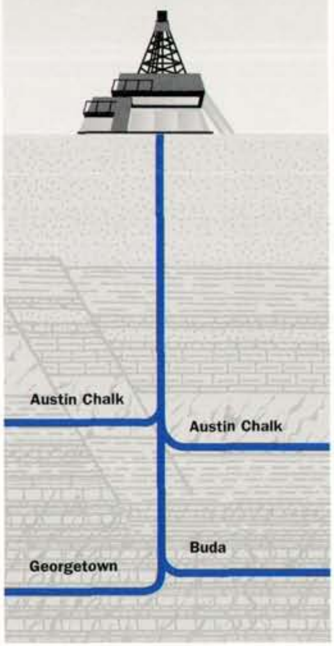
(cumulative wells)



Chesapeake is the second most active driller of horizontal wells in the U.S.

Horizontal Drilling Expertise

Chesapeake is now able to drill four laterals from one vertical wellbore.



Superior Operating Margin

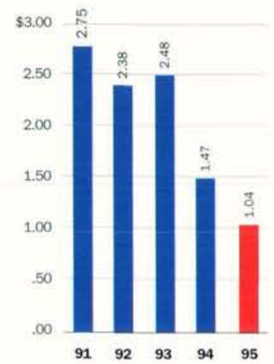
Chesapeake's fourth competitive advantage is our industry-leading operating margin. This margin is defined on a per-unit-of-production basis as oil and natural gas sales revenues minus operating costs (defined as lease operating expenses, production taxes, general and administrative expenses, and oil and gas depreciation, depletion, and amortization expenses). The key to creating shareholder value in the energy industry is the ability to generate high levels of cash flow that can be reinvested in a profitable search for new reserves.

Chesapeake maximizes its cash flow per unit of production by increasing its top-line revenues through production growth while carefully managing bottom-line costs. We have developed this industry-leading cost structure by:

- Utilizing horizontal drilling technology to reduce the per unit cost of finding and producing the company's oil and natural gas reserves;
- Concentrating the company's drilling in areas which provide the critical mass necessary to spread operating and overhead costs over a large number of wells;
- Operating 86% of the company's production, thereby allowing our employees to implement the most cost-effective and technologically advanced drilling, completing, and operating procedures, and;
- Maintaining a flat organizational structure which allows Chesapeake to evaluate and quickly respond to attractive opportunities.

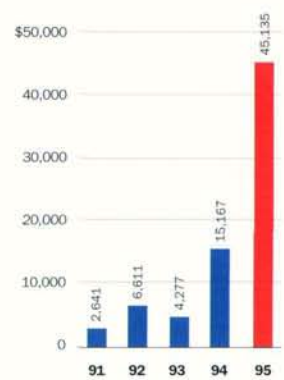
Because we believe oil and natural gas prices are likely to remain flat in the near term, the most profitable Mcf of gas or barrel of oil that can be produced is the one produced today. This is because long-lived reserves, burdened by future operating, financing, and administrative costs and adversely effected by the time value of money and the risk of future mechanical or reservoir problems, are less valuable than reserves that can be produced more quickly. As a result, reserves produced sooner rather than later have higher operating margins and are more likely to create shareholder value than those reserves produced in the future.

Improving Operating Efficiency
($ per Mcfe)



Chesapeake's industry-leading operating cost structure is a key to creating shareholder value.

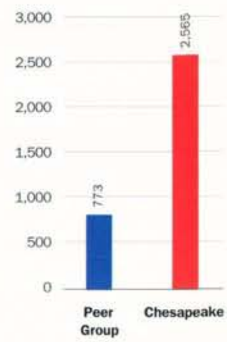
Cash Flow Growth
($ in thousands)



Chesapeake's drilling success has generated substantial cash flow growth.

Chesapeake attempts to develop large per-well oil and natural gas reserves with an average life of 5-6 years, shorter than the industry average of 8-10 years. The combination of accelerating the production of the company's reserves, generating high cash flows from the production, and then successfully reinvesting the cash flows into a technologically advanced exploration program can provide Chesapeake's shareholders with increasing value, even during periods of low oil and natural gas prices.

Reserves Per Well
(in MMcfe)



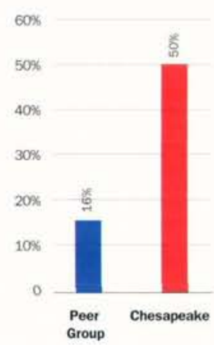
Chesapeake focuses on developing high-reserve properties which are more efficient to operate.

Management's Large Equity Stake

Chesapeake's fifth competitive advantage is management's ownership of approximately 50% of Chesapeake's equity, the highest in our peer group and among the highest of all NYSE-listed companies. This large ownership has created a culture of entrepreneurship in the company that results in more creative and productive employees. Furthermore, it closely aligns the interests of management and shareholders.

The daily decisions involved in managing Chesapeake's active and technically sophisticated drilling program are made quickly and implemented by employees who have direct lines of communication to management and have a significant stake in the outcome of those decisions. This flat organizational structure combined with our motivated work teams helps Chesapeake outmaneuver its competitors.

Management Ownership
(% of equity owned by management)



Management's interests are closely aligned with other shareholders' interests.

Looking Forward

Chesapeake's exploration strategy has always been based on three core beliefs:

- Large amounts of oil and natural gas reserves remain in unconventional reservoirs in the U.S.;
- Higher returns and value can be created by drilling new wells, and;
- Advances in technology will enable Chesapeake to continue lowering the cost of finding and producing oil and natural gas.

Chesapeake has grown during the past six years from five employees and $50,000 in assets to an industry leader with 200 employees and an enterprise value of $500 million. This success underscores the strengths of the company's strategy, its people, its assets, and its ability to utilize new technologies to discover and develop oil and natural gas reserves. Despite a cautious view that characterizes our industry, we are optimistic that Chesapeake can provide further increases in shareholder value through the company's competitive advantages, core beliefs, and exploration successes. We look forward to reporting further progress as we continue building Chesapeake into what we believe can be the premier independent energy producer in the U.S.

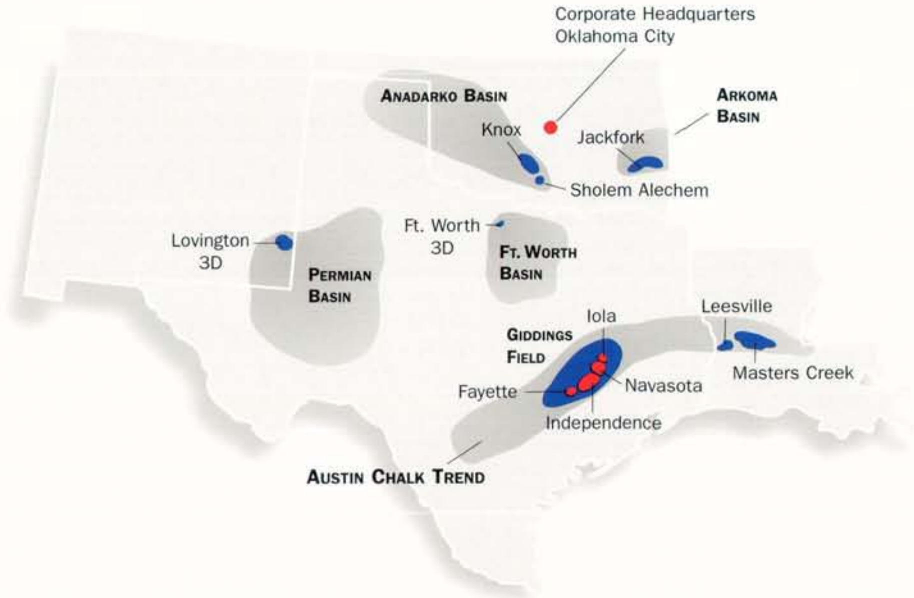
Large reserves remaining in unconventional resevoirs
+
Growth through the drillbit strategy
+
Chesapeake's technological expertise
=
Value created for Chesapeake shareholders

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

Tom L. Ward
President and Chief Operating Officer

October 1, 1995

Chesapeake's drilling activities are diversified over a number of different geographical areas and geological formations in an effort to reduce risk. Throughout these various prospect areas, the company utilizes such technologies as horizontal drilling, deep vertical drilling, high-pressure fracture stimulation, and enhanced 2-D and 3-D seismic to explore for and develop oil and natural gas reserves.



GIDDINGS FIELD

Chesapeake's most significant assets are located in the Giddings Field, one of the most active oil and natural gas fields in the U.S. Approximately 64% of the company's estimated proved reserves at June 30, 1995 were located in Giddings. The primary producing zone in the Giddings Field is the Austin Chalk formation, a fractured carbonate reservoir found at depths ranging from 7,000 feet to 16,000 feet along a 10,000 square mile trend in southeastern Texas and central Louisiana.

Chesapeake has concentrated its drilling efforts in the gas-prone downdip portion of the Giddings Field, where the Austin Chalk is deposited at depths below 11,000 feet. The company's downdip leasehold acreage is located in Brazos, Fayette, Grimes and Washington Counties, Texas. Chesapeake's engineers believe the downdip Giddings area is one of the largest discoveries of onshore gas in the United States in recent years.

The Austin Chalk is a tight geological formation which holds large volumes of oil and natural gas within its complex system of vertical fractures. Chesapeake has developed a significant technological niche in the downdip portion of the Giddings Field which has helped unlock the previously undeveloped reserves in

the downdip Austin Chalk. The company believes that its success in this area is attributable to four principal factors:

- the limited number of vertical wells previously drilled in the downdip portion of the field, thus significantly increasing the potential of locating virgin reservoirs;
- the company's aggressive leasehold acquisition program, which has permitted the creation of larger spacing units and thereby reduced possible competition for reserves from offsetting wells;
- the continued technological advances in horizontal drilling, which have significantly lowered finding costs, expanded the field's boundaries into deeper producing zones, and increased per well productivity through the ability to drill within a more tightly defined target zone, or "sweet spot," and;
- the presence of larger reserves in the downdip Austin Chalk which are under greater reservoir pressure and are in zones which are more intensively fractured than in updip Austin Chalk areas.

As a result of these factors, Chesapeake's downdip wells have, on average, produced greater per well reserves and depleted more slowly than average wells in other areas of Austin Chalk production.

Chesapeake's leasehold in the Giddings Field is concentrated in the downdip areas of Navasota River and Independence where the company now controls approximately 225,000 gross leasehold acres. Through September 30, 1995, Chesapeake had drilled 62 commercially productive wells in these two downdip areas and was drilling eight additional wells.

GIDDINGS FIELD
225,000 Acre Inventory
150 Undrilled Locations (86 Proven)
116 Producing Wells

NAVASOTA RIVER

In February 1994, Chesapeake drilled its first well in the Navasota River leasehold block, located in Brazos and Grimes Counties, Texas. As of September 30, 1995, the company had drilled and completed 48 consecutive successful Navasota River wells with five wells drilling. In fiscal 1996, Chesapeake has budgeted $22 million to drill 31 gross (12 net) wells in the Navasota River area. When fully developed, the company's 45,000 gross leasehold acres in Navasota River could support the drilling of a total of approximately 70 horizontal Austin Chalk wells.

NAVASOTA RIVER
45,000 Acre Inventory
75 Undrilled Locations (34 Proven)
48 Producing Wells
Horizontal – Austin Chalk, Buda and Georgetown

INDEPENDENCE

Located in Grimes and Washington Counties to the south and southwest (and further downdip) from the Navasota River area, Chesapeake's Independence block contains approximately 180,000 gross acres on which potentially 75 more horizontal wells can be drilled. As of September 30, 1995, the company had completed 14 Independence wells and was drilling three additional wells.

Chesapeake has budgeted $19 million to drill 16 gross (nine net) wells in fiscal 1996 in the Independence area. Because the Independence acreage block has the potential to contain more drilling locations than the Navasota River area and due to the larger retained working interest (54% versus 36%), Independence has the potential to generate greater net reserves to the company.

INDEPENDENCE

180,000 Acre Inventory
75 Undrilled Locations (10 Proven)
14 Producing Wells
Horizontal – Austin Chalk, Buda and Georgetown

KNOX

Based on Chesapeake's drilling success in the Golden Trend Field, the company initiated a deeper drilling project in early 1994 in the Knox area, approximately 10 miles to the southwest of the Golden Trend. Chesapeake's first two wells were completed in 1994 and were the first wells in Oklahoma to establish commingled commercial production from the Sycamore, Woodford, Hunton, and Viola formations at depths below 15,000 feet. Production from these initial wells significantly exceeded Chesapeake's initial expectations and has caused the company's drilling activity in Knox to increase substantially.

As of September 30, 1995, Chesapeake had completed 14 wells and was drilling or completing nine wells. Chesapeake's inventory of 50,000 gross acres in the Knox area could support the drilling of approximately 150 wells on current spacing requirements and up to an additional 150 increased density wells if the company determines drainage patterns justify smaller spacing units.

Knox contrasts with Giddings by having longer-lived (20+ years) gas reserves for which Chesapeake's independent reservoir engineers have assigned an average of approximately 3.5 Bcfe per well. The company has budgeted $15 million in fiscal 1996 to drill 22 gross (eight net) wells in the Knox area. Amerada Hess is Chesapeake's 50% non-operating partner in Knox.

KNOX

50,000 Acre Inventory
150 Undrilled Locations (32 Proven)
14 Producing Wells
Vertical – Sycamore, Woodford, Hunton and Viola
Amerada Hess 50% partner

Masters Creek

In December 1994, Occidental Petroleum Corporation ("Oxy") announced the completion of a deep, single lateral horizontal Austin Chalk discovery well in the Masters Creek area of central Louisiana at depths similar to those in the downdip Giddings area. According to Oxy's announcement, this well established production at rates equivalent to some of Chesapeake's best downdip Giddings wells with Oxy projecting ultimate reserves of approximately 9.0 Bcfe per dual-lateral completion.

The success of Oxy's initial well supports Chesapeake's geological and engineering premise that production from deep horizontal wells in the Austin Chalk are likely at other locations along a trend extending across southeastern Texas into central Louisiana. Oxy's well is 200 miles east of Chesapeake's activity in the Giddings Field and 60 miles east of the nearest commercial multi-well horizontal Austin Chalk production in the Brookeland Field where Sonat and Union Pacific Resources have established substantial Austin Chalk production.

Based upon Oxy's success, Chesapeake acquired 45,000 gross acres in Masters Creek in fiscal 1995. During the first quarter of fiscal 1996, the company increased this leasehold to 200,000 gross acres in Masters Creek and Leesville. Chesapeake owns 100% of this leasehold and does not currently intend to sell any of its interest prior to drilling its first well in the second quarter of fiscal 1996. The company has budgeted $9 million to drill three net wells during 1996.

Masters Creek / Leesville
200,000 Acre Inventory
3 Wells Projected in Fiscal 1996
Horizontal – Austin Chalk

Sholem Alechem

Another prospect area where the company has been able to utilize its horizontal drilling expertise is the Sholem Alechem portion of southern Oklahoma's Sho-Vel-Tum Field. Since its discovery more than 80 years ago, this field has produced more than one billion barrels of oil and one trillion cubic feet of natural gas. In 1994, Chesapeake initiated a horizontal drilling project based on the belief that the company's expertise with this technology could result in the recovery of significant new reserves in this area.

Chesapeake believes it has been proven correct with the completion of six horizontal Sycamore wells in the Sholem Alechem area through September 30, 1995. Preliminary estimates are for average recoverable reserves of 2.0 Bcfe per well at an estimated cost of $1.2 million. In fiscal 1996, the company has budgeted $4 million to drill an additional six gross (three net) wells in Sholem Alechem with the potential for drilling a total of 50 horizontal wells in the next few years. Texaco is Chesapeake's 50% non-operating partner in Sholem Alechem.

Sholem Alechem
25,000 Acre Inventory
50 Undrilled Locations (10 Proven)
6 Producing Wells
Horizontal - Sycamore
Texaco 50% partner

Arkoma Jackfork

In fiscal 1995, Chesapeake initiated a seismic and leasehold acquisition program in the Jackfork area of the Arkoma Basin of southeastern Oklahoma, the state's second largest gas basin. The Jackfork is a 50,000 gross acre prospect located in the southern portion of the Arkoma, a deeper and more geologically complex area that has been less heavily explored than the updip northern portion.

Chesapeake developed this prospect on the belief that recent developments in 2-D and 3-D seismic technology could identify large thrust sheets in the Jackfork formation which had been previously difficult to image using traditional 2-D seismic technology. The Jackfork prospect is targeting gas reserves from multiple payzones at depths from 8,000 to 15,000 feet. As of September 30, 1995, the company had drilled three Arkoma wells and was drilling three additional wells. Chesapeake has budgeted $5 million to drill eight gross (four net) wells during fiscal 1996.

Arkoma Jackfork

50,000 Acre Inventory

50 Undrilled Locations (11 Proven)

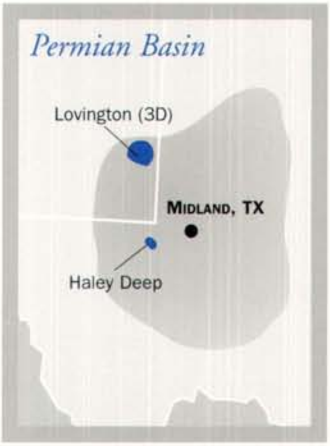
3 Producing Wells

Permian Basin

In fiscal 1995, Chesapeake initiated two new projects in the Permian Basin. The first is the Lovington Project in Lea County, New Mexico. In this area, the company is utilizing 3-D seismic technology to search for algal mound 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.

Using this new technology, Chesapeake has identified approximately 25 prospects in the Lovington Project and is currently acquiring leasehold rights for these prospects. The company is targeting oil reserves at depths from 11,000 to 13,000 feet in the project area. Chesapeake has budgeted $2 million for seismic acquistion and for drilling its first well in the second quarter of fiscal 1996.

Chesapeake's second project area in the Permian Basin is the Haley Deep Prospect in Winkler County, Texas. In this 4,500 gross acre prospect, Chesapeake is drilling a 21,000 foot Ellenburger exploratory well to an untested fault block. Chesapeake is the operator and owns a 30% working interest, Mobil owns 40%, and two private companies own the remaining 30%. Chesapeake has budgeted $1 million in fiscal 1996 for its share of drilling the initial well.

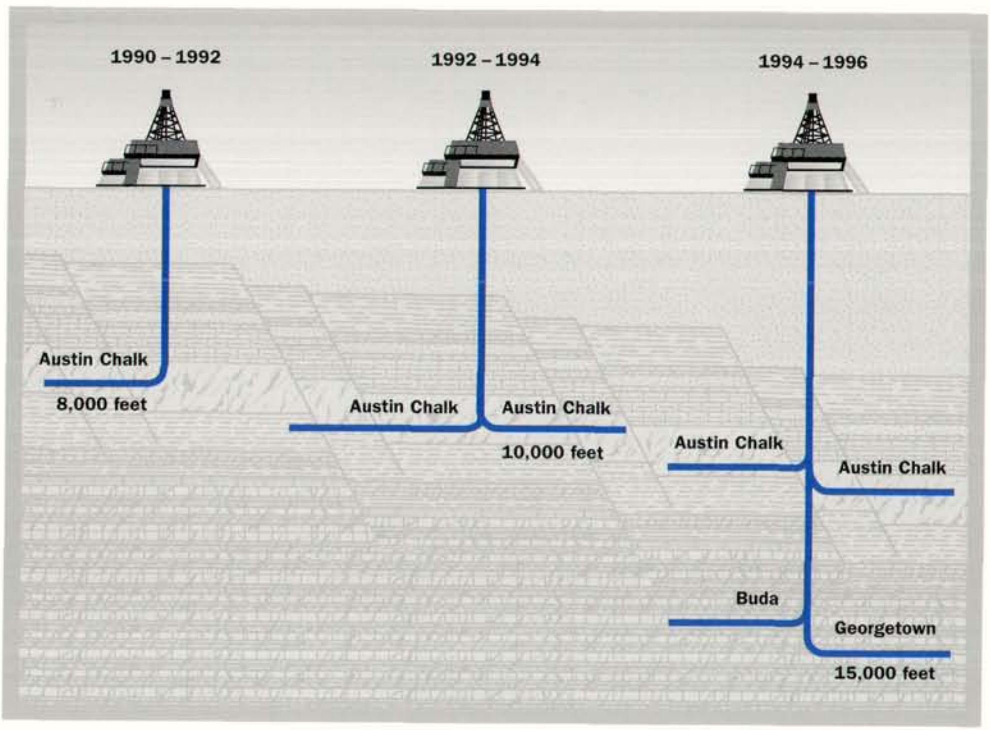


Other Horizontal Projects

Chesapeake is developing other horizontal projects in the Giddings Field, primarily in Fayette and Grimes Counties, Texas. These areas include a 20,000 gross acre joint venture with Union Pacific Resources, a 10,000 gross acre joint venture with Swift Energy in Fayette County, and a 30,000 gross acre position in the Iola area of northern Grimes County where Chesapeake is drilling horizontal Buda and Georgetown wells. The Buda and Georgetown formations, found less than 1,000 feet below the Austin Chalk, underlie most of the company's acreage in the Giddings Field and could provide significant future reserve additions. Chesapeake has budgeted $24 million to drill 28 gross (13 net) horizontal wells in these and other areas of Texas during fiscal 1996.

Chesapeake believes it has one of the largest and most diversified prospect inventories in the independent energy sector. In fiscal 1996, Chesapeake will continue leveraging its geological and engineering expertise into new project areas that can continue to increase and diversify the company's asset base.

Horizontal Drilling Evolution



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 CO_2 at high pressures and high rates.

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 70^0 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.

Mcfe. One thousand cubic feet of natural gas equivalent.

MMcf. One million cubic feet of natural gas.

MMcfe. One million cubic feet of natural gas equivalent.

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 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 a known reservoir(s) 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.

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.

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.

Directors

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

Tom L. Ward
President and
Chief Operating Officer
Oklahoma City, Oklahoma

Edgar F. Heizer, Jr.
Private Venture Capitalist
Chicago, Illinois

Breene M. Kerr
Chairman and President
Kerr Consolidated
Easton, Maryland

Shannon T. Self
Partner
Self, Giddens & Lees, Inc.
Oklahoma City, Oklahoma

Frederick B. Whittemore
Advisory Director
Morgan Stanley & Co.
New York, New York

Walter C. Wilson
General Agent
Massachusetts Mutual Life
Insurance Company
Houston, Texas

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Chairman of the Board and
Chief Executive Officer

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Chief Operating Officer

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Chief Financial Officer

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Vice President - Operations

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Vice President - Exploration

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Vice President - Land and Legal

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Vice President - Corporate
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Foreman

Colene Aldridge
Land Secretary

Sandra Alvarado
Lease Records Supervisor

Eduardo Alvarez-Salazar
Roustabout

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Drilling Manager

Eric Ashmore
Drilling Supervisor

Jack Austin
Geologist

Barbara Bale
Regulatory Analyst

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Joint Interest Senior Coordinator

Ralph Ball
Operating Systems Coordinator

Patti Baylor
Executive Assistant

Rodney Beverly
Drilling Foreman

Dean Billy
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Randy Borlaug
Purchasing Assistant

Phyllis Bray
Senior Accountant

James Brinkley
Welder

Carla Brittain
Geology Technician

Beverly Brown
Land Technician

Pamela Brown
Title Analyst

Martha Burger
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Jeff Burling
Geologist

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Shelli Butler
Accounting Assistant

John Calvin
Pumper

Ramon Carmona
Roustabout

Roberto Carmona
Roustabout

Leonardo Carmona
Foreman

John Carsrud
Drilling Superintendent

Ilan Cathey
Draftsman

David Chesher
Landman

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Field Foreman

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Legal Assistant

Kimberly Coffman
Operations Accounting Supervisor

Michael Coles
Pumper

Dale Cook, Jr.
Operations Accounting Supervisor

John Cooley, III
Service Company Accounting

Rose-Marie Coulter
Lease Analyst

Doug Crank
Equipment Operator

Lorre Cronk
Land Technician

Ken Davidson
Drilling Supervisor

Sheree Davis
Operations Accounting Coordinator

Ted Davis
Pumper

Kevin Decker
Service Company Coordinator

David DeSalvo
Pumper Foreman

Alton Dickey
Pumper

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Human Resources/ Compliance Manager

Mandy Duane
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Accounting File Maintenance

Jonnie Enyart
Lease Analyst

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Karla Fairchild
Land Assistant

David Ferguson
Landman

Rick Foster
Draftsman

Keri Fullingim
Drilling Secretary

Ed Gallegos
Production Engineer

Steve Gaskins
Foreman

Celia Gibson
Revenue Coordinator

Ronald Goff
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Traci Gonzales
Accounting Supervisor

Pat Goode
Oklahoma Land Manager

Brian Guire
Programmer

Cassandra Hamar
Administrative Assistant

Cheryl Hamilton
Staff Accountant

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Geophysicist

Monte Harlan
Pumper

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Gayle Harris
Divison Order Analyst

Marydith Harris
Production Accounting Assistant

Julie Hays
File Assistant

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Landman

Duane Hecklesberg
Geologist

Robert Hefner, IV
Geologist

David Higgins
Production Foreman

Carol Holden
Division Order Analyst

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Vice President - Land and Legal

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File Assistant

Pamala Huggins
Records Clerk

Richard Hughes
Production Foreman

Brian Imes
Administrative Services

Charles Imes
MIS Manager

Kim Imes
Lease Records Assistant

Lorrie Jacobs
Human Resources Assistant

Michael Johnson
Assistant Controller

Mike Johnston
Pumper

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Drilling Engineer

Darvin Knapp
Drilling Engineer

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Landman

Wesley Kruckenberg
Field Foreman

Steve Lane
Geologist

Jesse Langford
Landman

Dan LeDonne
Administrative Services Supervisor

Ron Lefaive
Controller

Mark Lester
Vice President - Exploration

Kirsten Lewellen
Senior Financial Reporting Analyst

Kinney Louthan
Landman

Heath Lovinggood
Operations Accountant

Marilyn Lynch
Lease Records Supervisor

Troy Mahan
Pumper

Felipe Maldonado
Roustabout

Meregildo Maldonado
Roustabout

Anthony Mann
Roustabout

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Equipment Operator

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Reservoir/Production Engineer

Aubrey McClendon
Chairman and CEO

Joe McClendon
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Roustabout

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Shannon McKanna
Receptionist

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Texas District Manager

Agustin Morales
Roustabout

Jose Morales
Foreman

Tommy Morphew
Pumper

Leland Murray
Pumper

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Greg Pearce
Field Supervisor

Michelle Peery
Payroll Assistant

Linda Peterburs
Staff Accountant

Randy Pierce
Purchasing Manager

Pat Pope
Operations Accounting Coordinator

Bobby Joe Portillo
Foreman

Fernando Portillo
Foreman

Tom Price, Jr.
Vice President - Corporate Development

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John Qualls
Pumper

Jimmy Randol
Roustabout

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Karyn Robles
Division Order Assistant

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Production Foreman

Pat Rolla
Geologist

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MIS Coordinator

Janna Rothwell
Service Company Accountant

Paul Rouse
Welder

Marc Rowland
Vice President - Finance and CFO

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Pumper

Jesus Salazar
Roustabout

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Tax Compliance

Patti Schlegel
Lease Records Supervisor

Charles Scholz
Pumper

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Landman

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Lease Analyst

Jana Skinner
Treasury Assistant

Linda Smedlund
Lease Records Analyst

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Attorney

Jay Smith
Senior Revenue Accountant

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Secretary

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Pumper

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MIS Coordinator

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Steve Ward
Administrative Services

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Safety Coordinator

Johnny White
Roustabout

Shelly White
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Joan Wilber
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Engineering Technician

Ranae Williams
Accounting Assistant

Jeff Williams
Landman

Thomas Williams
Drilling Engineer

Sharla Wilson
Executive Assistant

Stephanie Winn
Accounting Coordinator

Brian Winter
Geologist

Dave Wittman
Texas Production Manager

Jimmy Wright
Construction Foreman

Gerald Zgabay
Pumper

Karen Zinn
Production Accountant

STOCK DATA	**HIGH**	**LOW**	**LAST**
Fiscal 1993:			
Third Quarter	$ 6.13	$ 5.25	$ 6.13
Fourth Quarter	6.00	4.44	5.38
Fiscal 1994:			
First Quarter	$ 5.50	$ 3.13	$ 3.19
Second Quarter	3.88	2.25	2.87
Third Quarter	3.38	2.25	3.13
Fourth Quarter	4.44	2.50	3.88
Fiscal 1995:			
First Quarter	$11.00	$ 7.75	$10.63
Second Quarter	17.25	9.63	15.75
Third Quarter	21.75	10.00	21.25
Fourth Quarter	29.38	21.00	25.75

COMMON STOCK

Chesapeake Energy Corporation's common stock is listed on the New York Stock Exchange under the symbol CHK. As of September 30, 1995, there were approximately 3,300 beneficial owners of the common stock.

DIVIDENDS

The company's policy is to retain earnings to support the growth of the company. Chesapeake's Board of Directors has not authorized the payment of cash dividends on its common stock.

Form 10-K

Stockholders may obtain a copy of Chesapeake Energy Corporation's Form 10-K as filed with the Securities and Exchange Commission by contacting Thomas S. Price, Jr. at the address of the corporate offices above or by calling (405)848-8000, extension 257.

CORPORATE HEADQUARTERS

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(405)848-8000

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Oklahoma City, Oklahoma 73102
(405)272-9251

STOCK TRANSFER AGENT AND REGISTRAR

Liberty Bank & Trust Company of
Oklahoma City, N.A.
100 North Broadway Avenue
Oklahoma City, Oklahoma 73102
(405)231-6764

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

The following table sets forth selected consolidated financial data of the Company for each of the five fiscal years ended June 30, 1995. The data is derived from the financial statements of the Company which have been audited by Price Waterhouse LLP, independent accountants. 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 and related notes included elsewhere in this report.

	YEARS ENDED JUNE 30,				
	1995	1994	1993	1992	1991
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)				
STATEMENT OF OPERATIONS DATA:					
Revenues:					
Oil and gas sales	**$ 56,983**	$ 22,404	$ 11,602	$ 10,520	$ 4,334
Oil and gas service operations	**8,836**	6,439	5,526	7,656	1,961
Interest and other	**1,524**	981	880	542	148
Total	**67,343**	29,824	18,008	18,718	6,443
Costs and expenses:					
Production expenses and taxes	**4,256**	3,647	2,890	2,103	760
Oil and gas service operations	**7,747**	5,199	3,653	4,113	606
Oil and gas depreciation, depletion and amortization	**25,410**	8,141	4,184	2,910	1,585
Depreciation and amortization of other assets	**1,765**	1,871	557	974	351
General and administrative, net	**3,578**	3,135	3,620	3,314	2,119
Provision for legal and other settlements	**—**	—	1,286	—	—
Interest and other	**6,627**	2,676	2,282	2,577	317
Total costs and expenses	**49,383**	24,669	18,472	15,991	5,738
Income (loss) before income taxes	**17,960**	5,155	(464)	2,727	705
Income tax expense (benefit)	**6,299**	1,250	(99)	1,337	243
Net income (loss)	**$ 11,661**	$ 3,905	$ (365)	$ 1,390	$ 462
Dividends on preferred stock	**$ —**	$ —	$ 385	$ —	$ —
Net income (loss) per common share	**$ .94**	$ .36	$ (.10)	$ .22	$ .07
CASH FLOW DATA:					
Cash provided by (used in) operating activities	**$ 54,731**	$ 19,423	$ (1,499)	$ 11,550	$ 14,821
Cash used in investing activities	**112,703**	29,211	15,142	26,987	21,928
Cash provided by financing activities	**97,282**	21,162	20,802	12,779	9,247
BALANCE SHEET DATA: (AT END OF PERIOD)					
Working capital (deficit)	**$ 31,536**	$ 2,391	$ (9,994)	$(24,629)	$(15,661)
Total assets	**276,693**	125,690	78,707	61,095	44,462
Long-term debt, net of current maturities	**145,754**	47,878	14,051	22,154	8,570
Stockholders' equity (deficit)	**44,975**	31,260	31,432	132	(1,559)

OVERVIEW

Chesapeake's revenue, net income, operating cash flow, and production reached record levels in 1995. Increased cash flow from operations, combined with the issuance of $90 million in 10.5% Senior Notes in May 1995, enabled the company to fund its capital expenditure program of $106 million. During fiscal 1995, Chesapeake drilled 150 gross wells (51.4 net) and increased proved reserves by 100 Bcfe to 242 Bcfe as a result of this drilling, compared to 32 Bcfe of production.

The company has continued to emphasize the acquisition of prospective acreage, increasing its acreage holdings during fiscal 1995 to over 500,000 gross acres. During fiscal 1995, Chesapeake expanded its exploration efforts into the Masters Creek area of central Louisiana, the Arkoma Basin in southeastern Oklahoma, and the Lovington area of eastern New Mexico. Additionally, the company began testing fractured carbonate formations other than the Austin Chalk, such as the Buda and Georgetown in the Giddings Field. This extension of the company's exploration focus resulted in the acquisition of $24 million in prospective acreage during fiscal 1995.

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

	YEARS ENDED JUNE 30,		
	1995	1994	1993
Net Production Data:			
Oil (MBbl)	**1,139**	537	276
Gas (MMcf)	**25,114**	6,927	2,677
Gas equivalent (MMcfe)	**31,947**	10,152	4,333
Oil and Gas Sales ($ in 000's):			
Oil	**$19,784**	$ 8,111	$ 5,576
Gas	**37,199**	14,293	6,026
Total oil and gas sales	**$56,983**	$22,404	$11,602
Average Sales Price:			
Oil ($ per Bbl)	**$ 17.36**	$ 15.09	$ 20.20
Gas ($ per Mcf)	**$ 1.48**	$ 2.06	$ 2.25
Gas equivalent ($ per Mcfe)	**$ 1.78**	$ 2.21	$ 2.68
Oil and Gas Costs ($ per Mcfe):			
Production expenses and taxes	**$ 0.13**	$ 0.36	$ 0.67
General and administrative, net	**$ 0.11**	$ 0.31	$ 0.84
Depreciation, depletion and amortization	**$ 0.80**	$ 0.80	$ 0.97
Net Wells Drilled:			
Horizontal wells	**28.5**	11.1	3.4
Vertical wells	**23.0**	7.9	4.5

RESULTS OF OPERATIONS

GENERAL For the fiscal year ended June 30, 1995, Chesapeake realized net income of $11.7 million, or $0.94 per common share, on total revenues of $67.3 million. This compares with net income of $3.9 million, or $0.36 per common share, on total revenues of $29.8 million in fiscal 1994, and a net loss of $365,000, or $0.10 per common share, on total revenues of $18 million in fiscal 1993. The significantly higher earnings in fiscal 1995 were largely the result of higher production and lower costs per unit of production.

OIL AND GAS SALES During fiscal 1995, Chesapeake increased oil and gas sales 154% to $57.0 million versus $22.4 million for fiscal 1994 and 391% from the fiscal 1993 amount of $11.6 million. The increase in oil and gas sales resulted from strong growth in production volumes partially offset by decreased prices. For fiscal 1995, the company produced 31.9 Bcfe, at a weighted average price of $1.78 per Mcfe, compared to 10.2 Bcfe produced in fiscal 1994 at a weighted average price of $2.21 per Mcfe, and 4.3 Bcfe produced in fiscal 1993 at a weighted average price of $2.68 per Mcfe. This represents production growth of 214% and 642% over fiscal 1994 and 1993, respectively.

OIL AND GAS PRODUCTION The increases in production volumes during the year reflect Chesapeake's successful exploration and development program. The following table shows the company's production by major field area for fiscal 1995 and fiscal 1994:

	FOR THE YEARS ENDED JUNE 30, 1995		1994	
	PRODUCTION (MMCFE)	**PERCENT OF TOTAL**	PRODUCTION (MMCFE)	PERCENT OF TOTAL
Giddings				
- Navasota River	**16,881**	**53%**	2,546	26%
- Independence	**3,784**	**12**	—	—
- Other Giddings	**5,976**	**19**	4,289	42
Total Giddings	**26,641**	**84**	6,835	68
Oklahoma				
- Knox	**1,255**	**4**	83	1
- Golden Trend	**1,880**	**6**	1,252	12
- Sholem Alechem	**749**	**2**	348	3
Total Oklahoma	**3,884**	**12**	1,683	16
All Other Fields	**1,422**	**4**	1,634	16
Total Production	**31,947**	**100%**	10,152	100%

Natural gas production represented approximately 79% of Chesapeake's total production volumes on an equivalent basis in fiscal 1995. This compares to 68% in fiscal 1994 and 62% in fiscal 1993. This increasing natural gas concentration is a result of the company's drilling in deeper, more gas prone areas of the Giddings and Knox Fields. The change in production mix and the decreasing average gas prices realized by Chesapeake contributed to the decrease in average realized prices per Mcfe from fiscal 1993 to fiscal 1995.

OIL AND GAS PRICES For fiscal 1995, Chesapeake realized an average price per barrel of oil of $17.36, compared to $15.09 in fiscal 1994 and $20.20 in fiscal 1993. The company markets its oil on monthly average equivalent spot price contracts.

Chesapeake realized an average $1.48 per Mcf of natural gas sold during fiscal 1995, down 28% from fiscal 1994's average price of $2.06 per Mcf, and down 34% from fiscal 1993's average price of $2.25 per Mcf. The lower prices realized in fiscal 1995 resulted from lower natural gas prices and from an increasing portion of the company's gas production produced from areas with leaner natural gas that contains less liquids per Mcf. Chesapeake typically sells its natural gas under contracts that reflect spot market conditions.

HEDGING ACTIVITIES Periodically Chesapeake enters into futures contracts to hedge a portion of its future oil or gas production. The costs and the market value changes of these contracts are recognized as revenue when the contracts are closed. Chesapeake had no open hedging positions as of June 30, 1995.

SERVICE OPERATIONS Revenues from Chesapeake's service operations were $8.8 million in fiscal 1995, up 38% from $6.4 million in fiscal 1994, and up 60% from $5.5 million in 1993. The related costs and expenses of these operations were $7.7 million, $5.2 million and $3.7 million for the three years ended June 30, 1995, 1994 and 1993, respectively. The gross profit margin was 12% in fiscal 1995, down from 19% in fiscal 1994, and down from 34% in fiscal 1993. 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. During fiscal 1995, activity increased due to a higher number of wells drilled, but revenues did not increase proportionately because of the company's higher retained working interest in wells being provided services.

INTEREST AND OTHER Interest and other income for fiscal 1995 was $1.5 million compared to $1.0 million in 1994 and $0.9 million in 1993. This increase resulted from the company's larger average cash balances during fiscal 1995.

PRODUCTION EXPENSES AND TAXES Production expenses and taxes, which include lifting costs and production and excise taxes, increased to $4.3 million in fiscal 1995, as compared to $3.6 million in fiscal 1994, and $2.9 million in fiscal 1993. These increases on a year-to-year basis were the result of increased production. On a unit-of- production basis, production expenses and taxes decreased to $0.13 per Mcfe in fiscal 1995 compared to $0.36 per Mcfe in fiscal 1994 and $0.67 in fiscal 1993.

The decrease on a per unit basis is attributable to Chesapeake's high per well production average and to severance tax exemptions applicable to much of the company's gas production in the Navasota River, Independence and Knox areas during fiscal 1995.

DEPRECIATION, DEPLETION AND AMORTIZATION Depreciation, depletion and amortization ("DD&A") of oil and gas properties for fiscal 1995 was $25.4 million, $17.3 million higher than fiscal 1994's expense of $8.1 million, and $21.2 million higher than fiscal 1993's expense of $4.2 million. The average DD&A rate per Mcfe, which is a function of capitalized costs and related underlying reserves in the periods presented, remained constant at $0.80 in fiscal 1995 and 1994 and down from $0.97 in fiscal 1993.

DEPRECIATION AND AMORTIZATION OF OTHER ASSETS
Depreciation and amortization ("D&A") of other assets decreased to $1.8 million in fiscal 1995, compared to $1.9 million in fiscal 1994, and increased from $0.6 million in 1993. This decrease was caused by $285,000 of nonrecurring accelerated write-offs of capitalized loan costs incurred in fiscal 1994 for debts that were paid in full prior

to their respective scheduled payment dates with proceeds from the 12% Senior Notes, offset by an increase in D&A as a result of increased investments in depreciable service equipment and a full year of amortization of debt issuance costs as a result of the issuance of the 12% Senior Notes in March 1994.

GENERAL AND ADMINISTRATIVE, NET General and administrative ("G&A") expenses, which are net of capitalized internal payroll and non-payroll expenses, were $3.6 million in fiscal 1995, up 16% from $3.1 million in fiscal 1994, and constant with $3.6 million in fiscal 1993. On a per unit-of-production basis, G&A expenses declined to $0.11 per Mcfe in fiscal 1995 from $0.31 per Mcfe in fiscal 1994 and $0.84 per Mcfe in fiscal 1993. The increase in total G&A in fiscal 1995 and 1994 resulted primarily from increased personnel expenses required by the company's growth. G&A's expenses in fiscal 1993 were higher than in 1994 due to non-capitalized expenses related to Chesapeake's initial public offering in 1993.

PROVISION FOR LEGAL AND OTHER SETTLEMENTS During the fourth quarter of fiscal 1993, the company recorded a charge of $1.3 million for legal and other settlements. No such charges were incurred in fiscal 1994 or 1995.

INTEREST AND OTHER As a result of Chesapeake's higher debt levels, interest and other expense increased to $6.6 million in fiscal year 1995 as compared to $2.7 million in fiscal 1994 and $2.3 million in fiscal 1993.

INCOME TAX EXPENSE Chesapeake recorded income tax expense of $6.3 million in fiscal 1995, compared to $1.3 million in fiscal 1994, and compared to a benefit in 1993 of $99,000. All of the income tax expense in fiscal 1995 and 1994 was deferred due to a current year operating loss on a taxable basis resulting from the company's active drilling program. The effective tax rate of 35% in fiscal 1995 compares to a tax rate of 24% in 1994 and 21% in 1993.

Liquidity and Capital Resources

10.5% SENIOR NOTES On May 25, 1995, Chesapeake issued $90 million of 10.5% Senior Notes due 2002 (the "10.5% Senior Notes"). The 10.5% Senior Note Indenture provides for semiannual interest payments commencing December 1, 1995 with the principal due June 1, 2002. The 10.5% Senior Notes are redeemable at the option of the company at any time on or after June 1, 1999. Chesapeake may also redeem at its option at any time prior to June 1, 1998 up to $30 million of the 10.5% Senior Notes with the proceeds from an equity offering.

12.0% SENIOR NOTES On March 31, 1994, Chesapeake issued $47.5 million of 12% Senior Notes due 2001 (the "12% Senior Notes") and Warrants to purchase 973,750 shares of the company's Common Stock at $.01 per warrant ($.005 per share). The 12% Senior Note Indenture provides for semiannual interest payments, which commenced September 1, 1994, and for mandatory redemption of $11.9 million on each of March 1, 1998, 1999 and 2000.

All of Chesapeake's subsidiaries except Chesapeake Gas Development Corporation ("CGDC") have fully and unconditionally guaranteed on a joint and several basis both issues of senior notes, and the securities of the guaranteeing subsidiaries have been pledged to secure obligations under the 12% Senior Notes.

The 12% and 10.5% Senior Note Indentures contain certain covenants, including covenants limiting the company and the guaranteeing 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 guaranteeing subsidiaries; mergers or consolidations; and transactions with affiliates. Chesapeake is obligated to repurchase the 12% and 10.5% Senior Notes in the event of a change of control, the sale of certain assets, or failure to maintain a specified ratio of assets to debt.

WORKING CAPITAL Chesapeake had working capital of $31.5 million at June 30, 1995, compared to $2.4 million at June 30, 1994, and a working capital deficit of $9.9 million at June 30, 1993. The increase in working capital during fiscal 1995 is primarily attributable to the issuance of the 10.5% Senior Notes in May 1995. Additionally, the Company has an unused line of credit available from Union Bank of approximately $25 million.

OTHER CREDIT FACILITIES The company maintains a limited recourse bank facility currently in the amount of $11 million secured by oil and gas properties owned by Chesapeake's wholly-owned subsidiary CGDC. This facility provides for interest at the Union Bank reference rate. The facility is not guaranteed by Chesapeake or any of its other subsidiaries and is recourse only to the assets of CGDC. CGDC used proceeds borrowed under this facility to acquire producing oil and gas properties from Chesapeake Exploration Limited Partnership.

CASH FLOW ANALYSIS Cash provided by operating activities was $54.7 million in fiscal 1995, compared to cash provided by operating activities of $19.4 million in fiscal 1994, and cash used in operating activities of $1.5 million in 1993. The $35.3 million difference from fiscal 1995 to 1994 was primarily attributable to a $7.8 million increase in net income and $22.6 million increase in non-cash charges and to changes in current assets and liabilities from fiscal 1995 to 1994.

UTILIZATION OF CASH Significantly higher cash was used in fiscal 1995 for development, exploration, and acquisition of oil and gas properties compared to fiscal 1994 and 1993. Chesapeake expended $106 million in fiscal 1995 (net of proceeds from sale of leasehold, equipment and other services), compared to $28 million in fiscal 1994, and $13 million in fiscal 1993. Net cash proceeds received by Chesapeake for sales of leasehold, oil and gas equipment, and other services increased to $15 million in fiscal 1995, compared to $7.6 million in fiscal 1994, and $3.9 million in fiscal 1993.

PROCEEDS FROM FINANCING Cash flows from financing activities in fiscal 1995 reached $97 million, largely as the result of the May 1995 $90 million issuance of 10.5% Senior Notes, compared to $21.2 million in fiscal 1994 and $20.8 million in fiscal 1993.

CAPITAL EXPENDITURES Chesapeake has established a capital expenditure budget of $119 million to fund leasehold acquisition and drilling and completion activities during fiscal 1996. Of this total, the company expects to spend $51 million to develop a portion of its proved undeveloped reserves, $55 million for developing non-proved reserves, and $13 million for acreage acquisition and other corporate purposes.

Absent a significant increase in Chesapeake's drilling schedule, the company's internally generated cash flow, existing cash resources and bank credit facilities should be sufficient to fund its operating activities, budgeted capital expenditures, and debt service obligations in fiscal 1996. The discretionary nature of nearly all of Chesapeake's capital spending permits the company to make adjustments to its budget based upon factors such as oil and gas pricing, exploration and development drilling results, and the continued availability of internally generated or external capital resources.

PROVED RESERVES The following table sets forth Chesapeake's proved reserves in its primary operating areas (net of the interests of other working and royalty interest owners and others entitled to share in production), estimated capital expenditures and the number of potential drilling locations required to develop the company's proved undeveloped reserves at June 30, 1995:

	OIL (MBBL)	GAS (MMCF)	GAS EQUIVALENT (MMCFE)	PERCENT OF PROVED RESERVES	ESTIMATED CAPITAL EXPENDITURES REQUIRED TO DEVELOP ($ IN 000'S)	NUMBER OF PROVED UNDEVELOPED LOCATIONS
Navasota River	1,192	78,720	85,870	35.4%	$16,026	34
Independence	61	24,537	24,901	10.3	6,115	8
Fayette	1,085	22,705	29,217	12.0	10,448	35
Other Giddings	1,244	7,743	15,209	6.3	7,050	9
Subtotal Giddings	3,582	133,705	155,197	64.0	39,639	86
Knox	315	40,699	42,590	17.6	21,877	32
Golden Trend	318	13,428	15,339	6.3	3,861	21
Arkoma Jackfork	—	15,600	15,600	6.5	7,038	11
Other	901	8,377	13,779	5.6	4,128	10
Subtotal Non-Giddings	1,534	78,104	87,308	36.0	36,904	74
Total	5,116	211,809	242,505	100.0%	$76,543	160

To the Board of Directors and Stockholders
of Chesapeake Energy Corporation

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Chesapeake Energy Corporation and its subsidiaries (the "Company") at June 30, 1995 and 1994, and the results of their operations and their cash flows for each of the three years in the period 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 audits. We conducted our audits of these statements in accordance with generally accepted auditing standards which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PRICE WATERHOUSE LLP
Oklahoma City, Oklahoma
September 20, 1995

	JUNE 30, 1995	JUNE 30, 1994
	($ IN THOUSANDS)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 55,535	$ 16,225
Accounts receivable:		
Oil and gas sales	10,644	3,427
Joint interest and other, net of allowance for doubtful accounts of $452,000 and $350,000	26,317	14,020
Related parties	4,386	1,671
Inventory	8,926	7,162
Other	633	1,274
Total current assets	106,441	43,779
Property and equipment:		
Oil and gas properties, at cost based on full cost accounting:		
Evaluated oil and gas properties	165,302	83,170
Unevaluated properties	27,474	3,729
Less: accumulated depreciation, depletion and amortization	(41,821)	(16,417)
	150,955	70,482
Service properties, equipment, and other	16,966	10,697
Less: accumulated depreciation and amortization	(4,120)	(2,732)
Total property and equipment	163,801	78,447
Other assets	6,451	3,464
Total assets	$ 276,693	$ 125,690
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Notes payable and current maturities of long-term debt	$ 9,993	$ 7,576
Accounts payable	33,438	17,460
Accrued liabilities and other	7,572	4,162
Revenues and royalties due others	23,786	12,074
Income taxes payable	116	116
Total current liabilities	74,905	41,388
Long-term debt	145,754	47,878
Revenues and royalties due others	3,779	2,951
Deffered income taxes	7,280	2,213
Contingencies and commitments (Note 4)		
Stockholders' equity:		
Preferred stock, $.01 par value, 576,923 shares authorized; 0 shares issued and outstanding at June 30, 1995 and 1994, respectively	–	–
Common stock, $.005 par value, 20,000,000 shares authorized; 11,693,888 and 10,216,000 shares issued and outstanding at June 30, 1995 and 1994, respectively	58	51
Common stock warrants, exercise price of $.01 per warrant for 973,750 shares of common stock, 0 and 486,875 issued and outstanding at June 30, 1995 and 1994, respectively	–	5
Paid-in capital	30,295	28,243
Accumulated earnings	14,622	2,961
Total stockholders' equity	44,975	31,260
Total liabilities and stockholders' equity	$ 276,693	$ 125,690

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

	1995	1994	1993
		YEARS ENDED JUNE 30,	
	($ IN THOUSANDS, EXCEPT PER SHARE DATA)		
REVENUES:			
Oil and gas sales	$ 56,983	$ 22,404	$ 11,602
Oil and gas service operations	8,836	6,439	5,526
Interest and other	1,524	981	880
Total revenues	67,343	29,824	18,008
COSTS AND EXPENSES:			
Production expenses and taxes	4,256	3,647	2,890
Oil and gas service operations	7,747	5,199	3,653
Oil and gas depreciation, depletion and amortization	25,410	8,141	4,184
Depreciation and amortization of other assets	1,765	1,871	557
General and administrative, net	3,578	3,135	3,620
Provision for legal and other settlements	—	—	1,286
Interest and other	6,627	2,676	2,282
Total costs and expenses	49,383	24,669	18,472
Income (loss) before income taxes	17,960	5,155	(464)
Income tax expense (benefit)	6,299	1,250	(99)
Net income (loss)	$ 11,661	$ 3,905	$ (365)
Earnings per share computation:			
Net income (loss)	$ 11,661	$ 3,905	$ (365)
Dividends on preferred stock	—	—	385
Net income (loss) available to common	$ 11,661	$ 3,905	$ (750)
Net income (loss) per common share	$ .94	$ .36	$ (.10)
Weighted average common and common equivalent shares outstanding	12,416	10,720	7,456

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

	1995	1994	1993
		YEARS ENDED JUNE 30, ($ IN THOUSANDS)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (loss)	$ 11,661	$ 3,905	$ (365)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	26,628	9,455	4,741
Deferred taxes	6,299	1,250	(99)
Amortization of loan costs	548	557	127
Amortization of bond discount	567	138	—
Bad debt expense	308	222	—
Gain on sale of fixed assets	(108)	—	—
CHANGES IN CURRENT ASSETS AND LIABILITIES:			
(Increase) decrease in accounts receivable	(19,795)	(7,682)	401
(Increase) decrease in accounts receivable - related parties	(2,715)	(91)	(1,580)
(Increase) decrease in inventory	(1,203)	(304)	834
Decrease (increase) in other current assets	614	(726)	(247)
Increase (decrease) in accounts payable, accrued liabilities and other	19,387	10,186	(11,472)
Increase in current and non-current revenues and royalties due others	12,540	2,622	6,161
(Decrease) in income taxes payable	—	(109)	—
Cash provided by (used in) operating activities	54,731	19,423	(1,499)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Exploration development and acquisition of oil and gas properties	(120,985)	(34,654)	(16,806)
Proceeds from sale of oil and gas equipment, leasehold and other	15,107	7,598	3,943
Other proceeds from sales	1,104	765	—
Other property and equipment additions	(7,929)	(2,920)	(2,279)
Cash used in investing activities	(112,703)	(29,211)	(15,142)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of Common Stock	—	—	25,168
Proceeds from long-term borrowings	128,834	48,800	19,762
Payments on long-term borrowings	(32,370)	(25,738)	(23,487)
Placement fee on Senior Notes and Warrants	—	(1,900)	—
Other financing	—	—	(641)
Cash received from exercise of stock options	818	—	—
Cash provided by financing activities	97,282	21,162	20,802
Net increase in cash and cash equivalents	39,310	11,374	4,161
Cash and cash equivalents, beginning of period	16,225	4,851	690
Cash and cash equivalents, end of period	$ 55,535	$ 16,225	$ 4,851
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
CASH PAYMENTS FOR:			
Interest expense	$ 6,488	$ 1,467	$ 2,520
Income taxes	$ —	$ 109	$ 56

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

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

During the year ended June 30, 1993, notes payable of $7.5 million were converted to preferred stock.

The Company has a financing arrangement with a vendor to supply certain oil and gas equipment inventory. The total amounts owed at June 30, 1995, 1994 and 1993 were $6,513,000, $5,952,000 and $2,498,000, respectively. No cash consideration is exchanged for inventory until actual draws on the inventory are made.

On March 31, 1994, the Company issued 8,000 units (see Note 2) to Trust Company of the West ("TCW") primarily in consideration for the surrender of 576,923 shares of the Company's 9% convertible preferred stock, including its rights to dividends ($725,000 accrued but unpaid at December 31, 1993), warrants to purchase Common Stock and an overriding royalty interest.

In February 1994, pending litigation was settled pursuant to an agreement requiring COI, a subsidiary of the Company, to pay $1.25 million, of which $250,000 plus interest was paid in July 1994, and the balance of which was paid in June 1995.

During fiscal 1995, the Company recognized an income tax benefit of $1,229,000 related to the disposition of stock options in fiscal 1995. The tax benefit was recorded as an adjustment to deferred income taxes and paid-in capital on the accompanying consolidated balance sheets.

Proceeds from the issuance of the $90 million 10.5% Senior Note offering in May 1995 are net of a $2.7 bond placement fee which was deducted from the actual cash received.

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	1995	YEARS ENDED JUNE 30, 1994	1993
		($ IN THOUSANDS)	
Preferred stock			
Balance, beginning of period	$ —	$ 6	$ —
Exchange of 576,923 shares of preferred stock	—	(6)	—
Issuance of 576,923 shares of preferred stock	—	—	6
Balance, end of period	—	—	6
Common stock:			
Balance, beginning of period	51	51	28
Issuance of 4,600,000 shares of common stock	—	—	23
Exercise of stock options and warrants	7	—	—
Balance, end of period	58	51	51
Common stock warrant:			
Balance, beginning of period	5	—	—
Issuance of common stock warrants	—	5	—
Exercise of common stock warrants	(5)	—	—
Balance, end of period	—	5	—
Paid-in capital:			
Balance, beginning of period	28,243	32,704	683
Exchange of preferred stock	—	(7,494)	—
Issuance of common stock warrants	—	3,033	—
Issuance of preferred stock	—	—	7,494
Exercise of stock options and warrants	823	—	—
Issuance of common stock	—	—	25,668
Offering expenses and other	—	—	(1,141)
Tax benefit from exercise of stock options	1,229	—	—
Balance, end of period	30,295	28,243	32,704
Accumulated earnings (deficit):			
Balance, beginning of period	2,961	(1,329)	(579)
Net income (loss)	11,661	3,905	(365)
Preferred dividends	—	(340)	(385)
Cancellation of preferred dividends	—	725	—
Balance, end of period	14,622	2,961	(1,329)
Total stockholders' equity	$ 44,975	$ 31,260	$ 31,432

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

1. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION The accompanying consolidated financial statements of Chesapeake Energy Corporation (the "Company") include the accounts of Chesapeake Operating, Inc. ("COI"), Chesapeake Exploration Limited Partnership ("CEX"), a limited partnership, Chesapeake Gas Development Corporation ("CGDC"), Lindsay Oil Field Supply, Inc., Sander Trucking Company, Inc. and subsidiaries of those entities. All significant intercompany accounts and transactions have been eliminated.

CASH EQUIVALENTS For purposes of the consolidated financial statements, the Company considers investments in all highly liquid debt instruments purchased with original maturities of three months or less to be cash equivalents.

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 in its service operations and is carried at the lower of cost or market, on the specific identification method.

PROPERTY AND EQUIPMENT 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 10. 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 annually by independent petroleum engineers. The average composite rates used for depreciation, depletion and amortization were $.80, $.80 and $.97 per equivalent Mcf in 1995, 1994, and 1993, 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. Unamortized costs as reduced by related deferred taxes are subject to a ceiling which limits such amounts to the estimated present value of oil and gas reserves, reduced by operating expenses, future development costs and income taxes. The costs of unproved properties are excluded from amortization until the properties are evaluated.

OTHER PROPERTY AND EQUIPMENT Other property and equipment primarily consists of vehicles, oil and gas servicing equipment, 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 over the estimated useful lives of the assets, which range from three to 30 years.

LEASES The Company leases certain office facilities under an operating lease expiring in August 1, 1996. Included in service properties, equipment and other in the consolidated balance sheets is computer equipment, software, and certain other office equipment held under capital leases. Minimum lease payments under these operating and capital leases are as follows:

	CAPITAL LEASES	OPERATING LEASES
	($ IN THOUSANDS)	
1996	$ 77	$ 61
1997	68	—
1998	62	—
1999	15	—
2000	—	—
Total minimum lease payments	$222	$ 61
Less: amount relating to interest	41	
Present value of minimum payments	$181	

CAPITALIZED INTEREST During fiscal 1995, 1994 and 1993, interest of approximately $1,574,000, $356,000 and $192,000 was capitalized on significant investments in unproved properties that are not being currently depreciated, depleted, or amortized and on which exploration or development activities are in progress.

SERVICE OPERATIONS Certain subsidiaries of the Company perform contractual services on wells the Company operates as well as for third parties. 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 is not affected by the performance of these contractual services and all intercompany profits have been eliminated.

CONCENTRATION OF CREDIT RISK The Company operates exclusively in the oil and gas industry. The Company's joint interest billings and oil and gas sales receivables represent substantially all of the balance included in trade accounts receivable in the accompanying balance sheets.

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 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 PER SHARE Primary earnings per share for all periods have been computed based upon the weighted average number of shares of Common Stock outstanding after giving retroactive effect to all stock splits and the issuance of common stock equivalents. Computations of primary and fully diluted earnings per share have not given effect to common stock equivalents or other contingent issuances for any period in which their inclusion would have the effect of increasing or decreasing the earnings or loss per share amount otherwise computed. Dilutive options or warrants which are issued during a period or which expire or are cancelled during a period are reflected in both primary and fully diluted earnings per share computations for the time they were outstanding during the period being reported upon.

GAS IMBALANCES The Company follows the "sales method" of accounting for its oil and gas revenue whereby the Company recognizes sales revenue on all oil or 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 reserves on the underlying properties. The Company's net imbalance positions at June 30, 1995 and 1994 were not material.

ACCOUNTING FOR FUTURES CONTRACTS Periodically, the Company enters into futures contracts to hedge a portion of its future oil and gas production. Since these contracts qualify as hedges and correlate to price movements of oil and gas production, any gains or losses from market changes are recognized when the contracts are closed. There were no open futures contracts at June 30, 1995.

DEBT ISSUE COSTS Other assets relate primarily to debt issue costs associated with the issuance of the 12% Senior Notes on March 31, 1994 and the 10.5% Senior Notes on May 25, 1995 (see Note 2). The remaining unamortized costs on both issuances of Senior Notes at June 30, 1995 totaled $6.4 million and are being amortized over the life of the Senior Notes.

FAIR VALUE OF FINANCIAL INSTRUMENTS The Company's financial instruments consist primarily of cash and cash equivalents, trade receivables, trade payables, and debt instruments. Fair value estimates have been determined by the Company, using available market information and appropriate valuation methodologies. These estimates are subjective in nature and involve uncertainties and matters of significant judgment, and therefore cannot be determined with precision.

The carrying value of cash and cash equivalents, trade receivables and trade payables are considered to be representative of their respective fair values, due to the short maturity of these instruments. Based on the borrowing rates currently available to the Company for bank loans with similar terms and average maturities, the fair market value of long-term debt and notes payable approximates its carrying value.

RECLASSIFICATIONS Certain reclassifications have been made to the consolidated financial statements for the years ended June 30, 1994 and 1993 to conform to the presentation used for the June 30, 1995 consolidated financial statements.

2. SENIOR NOTES

On May 25, 1995, the Company completed a private offering of $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 any time prior to June 1, 1998 up to $30 million of the 10.5% Senior Notes with the proceeds of an equity offering. In September 1995, the Company exchanged the 10.5% Senior Notes for substantially identical notes in a registered exchange offer.

On March 31, 1994, the Company completed a private offering of 47,500 Units consisting of an aggregate of $47.5 million principal amount of 12% Senior Notes due 2001 ("12% Senior Notes") and warrants ("Warrants") to purchase 973,750 shares of the Company's Common Stock at an exercise price of $.01 per Warrant. All of the Warrants were subsequently exercised. In exchange for 8,000 Units, the Company acquired from Trust Company of the West ("TCW") 576,923 shares of the Company's 9% cumulative convertible preferred stock and all rights to dividends thereon, warrants to purchase 624,002 shares of the Company's Common Stock and 50% of an outstanding overriding royalty interest held by TCW. The 12% Senior Notes are redeemable at the option of the Company at any time on or after March 1, 1998. In November 1994, the Company exchanged the 12% Senior Notes for substantially identical notes in a registered exchange offer (in either case, the "12% Senior Notes").

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 12% Senior Notes and 10.5% 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 Notes): COI, Lindsay Oil Field Supply, Inc., Sander Trucking Company, Inc., Whitmire Dozer Service, Inc. and CEX (collectively, the "Subsidiary Guarantors"). The only subsidiary of the Company that is not a Subsidiary Guarantor is CGDC, which was formed in December 1994. Each of the Subsidiary Guarantors is a direct or indirect wholly-owned subsidiary of the Company. The securities of the Subsidiary Guarantors have been pledged to secure performance of the Company's obligations under the 12% Senior Notes. The only affiliate securities constituting a substantial portion of the collateral for the 12% Senior Notes are the partnership interests in CEX.

The 12% and 10.5% Senior Note Indentures contain certain covenants, including covenants limiting the Company and the Subsidiary Guarantors 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 subsidiary Guarantors; mergers or consolidations; and transactions with affiliates. The Company is also obligated to repurchase 12% and 10.5% Senior Notes if it fails to maintain a specified ratio of assets to debt and in the event of a change of control or certain asset sales.

The Company's bank credit agreement prohibits any distributions by CEX to its partners (the Company and COI) if the maturity of any obligations to the lender has been accelerated. The pledge agreement relating to the 12% Senior Notes requires that all dividends and distributions from Subsidiary Guarantors be paid to the collateral agent thereunder upon an event of default under the 12% Senior Notes Indenture. There are no other restrictions on the payment of cash dividends by Subsidiary Guarantors.

CEX is a limited partnership which is 10% owned by COI, as sole general partner, and 90% owned directly by the Company, as sole limited partner. CEX owns 86% and CGDC owns 14% of the Company's producing oil and gas properties, based on the present value of future net revenue at June 30, 1995 (discounted at 10%).

Set forth below are condensed consolidating financial statements of CEX, the other Subsidiary Guarantors, all Subsidiary Guarantors combined, CGDC and the Company. The CEX limited partnership condensed financial statements were prepared on a separate entity basis as reflected in the Company's books and records and include all material costs of doing business as if the partnership were on a stand-alone basis except that interest is not charged or allocated. No provision has been made for income taxes because the partnership is not a taxpaying entity.

AS OF JUNE 30, 1995

		SUBSIDIARY GUARANTORS					
	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
				($ IN THOUSANDS)			
ASSETS							
Current assets:							
Cash and cash equivalents	$ —	$ 53,227	$ 53,227	$ 5	$ 2,303	$ —	$ 55,535
Accounts receivable	9,867	30,693	40,560	777	10	—	41,347
Inventory	—	8,895	8,895	31	—	—	8,926
Other	—	633	633	—	—	—	633
Total current assets	9,867	93,448	103,315	813	2,313	—	106,441
Property and equipment:							
Oil and gas properties	163,521	(16,723)	146,798	18,504	—	—	165,302
Unevaluated leasehold	27,474	—	27,474	—	—	—	27,474
Other property and equipment	—	12,199	12,199	—	4,767	—	16,966
Less: accumulated depreciation, depletion and amortization	(36,959)	(3,847)	(40,806)	(4,861)	(274)	—	(45,941)
	154,036	(8,371)	145,665	13,643	4,493	—	163,801
Investments in subsidiaries and intercompany advances	17,559	181,914	199,473	—	176,795	(376,268)	—
Other assets	776	41	817	123	5,511	—	6,451
Total assets	$182,238	$267,032	$449,270	$ 14,579	$189,112	$(376,268)	$276,693
LIABILITIES AND STOCKHOLDERS' EQUITY							
Current liabilities:							
Notes payable and current maturities of long-term debt	$ —	$ 7,757	$ 7,757	$ 2,200	$ 36	$ —	$ 9,993
Accounts payable and other	516	61,777	62,293	—	2,619	—	64,912
Total current liabilities	516	69,534	70,050	2,200	2,655	—	74,905
Long-term debt	10	1,326	1,336	8,600	135,818	—	145,754
Revenues payable	—	3,779	3,779	—	—	—	3,779
Deferred income taxes	—	9,621	9,621	164	(2,505)	—	7,280
Intercompany payables	140,236	201,959	342,195	3,307	30,766	(376,268)	—
Stockholders' equity:							
Common stock	—	31	31	1	58	(32)	58
Common stock warrants	—	—	—	—	—	—	—
Preferred stock	—	—	—	—	—	—	—
Other	41,476	(19,218)	22,258	307	22,320	32	44,917
	41,476	(19,187)	22,289	308	22,378	—	44,975
Total liabilities and stockholders' equity	$182,238	$267,032	$449,270	$ 14,579	$189,112	$(376,268)	$276,693

AS OF JUNE 30, 1994

	Subsidiary Guarantors						
	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
				($ IN THOUSANDS)			
ASSETS							
Current assets:							
Cash and cash equivalents	$ —	$ 13,946	$ 13,946	$ —	$ 2,279	$ —	$ 16,225
Accounts receivable	8,686	10,432	19,118	—	—	—	19,118
Inventory	—	7,162	7,162	—	—	—	7,162
Other	—	1,274	1,274	—	—	—	1,274
Total current assets	8,686	32,814	41,500	—	2,279	—	43,779
Property and equipment:							
Oil and gas properties	94,717	(11,547)	83,170	—	—	—	83,170
Unevaluated leasehold	3,729	—	3,729	—	—	—	3,729
Other property and equipment	—	8,155	8,155	—	2,542	—	10,697
Less: accumulated depreciation, depletion and amortization	(16,417)	(2,568)	(18,985)	—	(164)	—	(19,149)
	82,029	(5,960)	76,069	—	2,378	—	78,447
Investments in subsidiaries and intercompany advances	1,033	61,521	62,554	—	69,238	(131,792)	—
Other assets	712	10	722	—	2,742	—	3,464
Total assets	$ 92,460	$ 88,385	$ 180,845	$ —	$ 76,637	$(131,792)	$125,690
LIABILITIES AND STOCKHOLDERS' EQUITY							
Current liabilities:							
Notes payable and current maturities of long-term debt	$ —	$ 7,543	$ 7,543	$ —	$ 33	$ —	$ 7,576
Accounts payable and other	—	32,587	32,587	—	1,225	—	33,812
Total current liabilities	—	40,130	40,130	—	1,258	—	41,388
Long-term debt	10	2,550	2,560	—	45,318	—	47,878
Revenues payable	—	2,951	2,951	—	—	—	2,951
Deferred income taxes	—	2,363	2,363	—	(150)	—	2,213
Intercompany payables	76,707	53,039	129,746	—	2,046	(131,792)	—
Stockholders' equity:							
Common stock	—	36	36	—	51	(36)	51
Common stock warrants	—	—	—	—	5	—	5
Preferred stock	—	9	9	—	—	(9)	—
Other	15,743	(12,693)	3,050	—	28,109	45	31,204
	15,743	(12,648)	3,095	—	28,165	—	31,260
Total liabilities and stockholders' equity	$ 92,460	$ 88,385	$ 180,845	$ —	$ 76,637	$(131,792)	$125,690

FOR THE YEAR ENDED JUNE 30, 1995

	SUBSIDIARY GUARANTORS						
	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
				($ IN THOUSANDS)			
REVENUES							
Oil and gas sales	$ 55,417	$ —	$ 55,417	$ 1,566	$ —	$ —	$ 56,983
Oil and gas service operations	—	8,836	8,836	—	—	—	8,836
Other	—	1,394	1,394	—	130	—	1,524
	55,417	10,230	65,647	1,566	130	—	67,343
COSTS AND EXPENSES							
Production expenses and taxes	3,494	551	4,045	211	—	—	4,256
Oil and gas service operations	—	7,747	7,747	—	—	—	7,747
Oil and gas depreciation, depletion and amortization	24,769	6	24,775	635	—	—	25,410
Other depreciation and amortization	138	1,107	1,245	5	515	—	1,765
General and administrative, net	931	1,689	2,620	58	900	—	3,578
Interest and other	352	218	570	184	5,873	—	6,627
	29,684	11,318	41,002	1,093	7,288	—	49,383
Income (loss) before income tax	25,733	(1,088)	24,645	473	(7,158)	—	17,960
Income tax expense (benefit)	—	8,639	8,639	165	(2,505)	—	6,299
Net income (loss)	$ 25,733	$ (9,727)	$ 16,006	$ 308	$ (4,653)	$ —	$ 11,661

FOR THE YEAR ENDED JUNE 30, 1994

	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
REVENUES							
Oil and gas sales	$ 22,404	$ —	$ 22,404	$ —	$ —	$ —	$ 22,404
Oil and gas service operations	—	6,439	6,439	—	—	—	6,439
Interest and other	—	622	622	—	359	—	981
	22,404	7,061	29,465	—	359	—	29,824
COSTS AND EXPENSES							
Production expenses and taxes	3,185	462	3,647	—	—	—	3,647
Oil and gas service operations	—	5,199	5,199	—	—	—	5,199
Oil and gas depreciation	8,141	—	8,141	—	—	—	8,141
Other depreciation and amortization	171	1,536	1,707	—	164	—	1,871
General and administrative, net	823	2,169	2,992	—	143	—	3,135
Interest and other	507	1,492	1,999	—	677	—	2,676
	12,827	10,858	23,685	—	984	—	24,669
Income (loss) before income tax	9,577	(3,797)	5,780	—	(625)	—	5,155
Income tax expense (benefit)	—	1,400	1,400	—	(150)	—	1,250
Net income (loss)	$ 9,577	$ (5,197)	$ 4,380	$ —	$ (475)	$ —	$ 3,905

FOR THE YEAR ENDED JUNE 30, 1993

	SUBSIDIARY GUARANTORS						
	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
				($ IN THOUSANDS)			
REVENUES							
Oil and gas sales	$ 11,602	$ —	$ 11,602	$ —	$ —	$ —	$ 11,602
Oil and gas service operations	—	5,526	5,526	—	—	—	5,526
Interest and other	5	843	848	—	32	—	880
	11,607	6,369	17,976	—	32	—	18,008
COSTS AND EXPENSES							
Production expenses and taxes	2,615	275	2,890	—	—	—	2,890
Oil and gas service operations	—	3,653	3,653	—	—	—	3,653
Oil and gas depreciation	4,184	—	4,184	—	—	—	4,184
Other depreciation and amortization	114	431	545	—	12	—	557
General and administrative, net	862	2,742	3,604	—	16	—	3,620
Provision for legal settlements	—	1,286	1,286	—	—	—	1,286
Interest and other	1,829	450	2,279	—	3	—	2,282
	9,604	8,837	18,441	—	31	—	18,472
Income (loss) before income tax	2,003	(2,468)	(465)	—	1	—	(464)
Income tax expense (benefit)	—	(99)	(99)	—	—	—	(99)
Net income (loss)	$ 2,003	$(2,369)	$ (366)	$ —	$ 1	$ —	$ (365)

FOR THE YEAR ENDED JUNE 30, 1995

	SUBSIDIARY GUARANTORS						
	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
				($ IN THOUSANDS)			
CASH FLOWS FROM OPERATING ACTIVITIES	$ 50,906	$ 9,143	$ 60,049	$ 305	$ (4,692)	$ (931)	$ 54,731
CASH FLOWS FROM INVESTING ACTIVITIES:							
Oil and gas properties	(116,133)	(743)	(116,876)	(4,109)	—	—	(120,985)
Proceeds from sales	16,579	11,132	27,711	—	—	(11,500)	16,211
Purchase of oil and gas properties	—	—	—	(11,500)	—	11,500	—
Other additions	—	(7,929)	(7,929)	—	—	—	(7,929)
	(99,554)	2,460	(97,094)	(15,609)	—	—	(112,703)
CASH FLOW FROM FINANCING ACTIVITIES							
Proceeds from borrowings	28,433	1,601	30,034	11,500	87,300	—	128,834
Payments on borrowings	(28,433)	(3,599)	(32,032)	(700)	362	—	(32,370)
Intercompany advances, net	48,648	29,676	78,324	4,509	(83,764)	931	—
Cash received from exercise of stock options	—	—	—	—	818	—	818
	48,648	27,678	76,326	15,309	4,716	931	97,282
NET INCREASE IN CASH AND CASH EQUIVALENTS	—	39,281	39,281	5	24	—	39,310
Cash, beginning of period	—	13,946	13,946	—	2,279	—	16,225
Cash, end of period	$ —	$ 53,227	$ 53,227	$ 5	$ 2,303	$ —	$ 55,535

FOR THE YEAR ENDED JUNE 30, 1994

	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
CASH FLOWS FROM OPERATING ACTIVITIES	$ 13,131	$ 7,707	$ 20,838	$ —	$ (1,415)	$ —	$ 19,423
CASH FLOWS FROM INVESTING ACTIVITIES							
Oil and gas properties	(33,466)	(1,188)	(34,654)	—	—	—	(34,654)
Proceeds from sales	3,268	5,095	8,363	—	—	—	8,363
Other additions	(159)	(1,782)	(1,941)	—	(979)	—	(2,920)
	(30,357)	2,125	(28,232)	—	(979)	—	(29,211)
CASH FLOW FROM FINANCING ACTIVITIES							
Proceeds from borrowings	—	8,800	8,800	—	40,000	—	48,800
Payments on borrowings	(10,201)	(15,537)	(25,738)	—	—	—	(25,738)
Intercompany advances, net	27,250	6,715	33,965	—	(33,965)	—	—
Other financing	—	—	—	—	(1,900)	—	(1,900)
	17,049	(22)	17,027	—	4,135	—	21,162
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(177)	9,810	9,633	—	1,741	—	11,374
Cash, beginning of period	177	4,136	4,313	—	538	—	4,851
Cash, end of period	$ —	$ 13,946	$ 13,946	$ —	$ 2,279	$ —	$ 16,225

FOR THE YEAR ENDED JUNE 30, 1993

	SUBSIDIARY GUARANTORS						
	CEX	OTHERS	COMBINED	CGDC	COMPANY (PARENT)	ELIMINATIONS	CONSOLIDATED
				($ IN THOUSANDS)			
CASH FLOWS FROM OPERATING ACTIVITIES	$ 4,675	$ (6,187)	$ (1,512)	$ —	$ 13	$ —	$ (1,499)
CASH FLOWS FROM INVESTING ACTIVITIES:							
Oil and gas properties	(18,085)	1,279	(16,806)	—	—	—	(16,806)
Proceeds from sales	1,374	2,569	3,943	—	—	—	3,943
Other additions	(819)	(1,460)	(2,279)	—	—	—	(2,279)
	(17,530)	2,388	(15,142)	—	—	—	(15,142)
CASH FLOW FROM FINANCING ACTIVITIES:							
Issuance of common stock	—	—	—	—	25,168	—	25,168
Proceeds from borrowings	—	18,985	18,985	—	777	—	19,762
Payments on borrowings	(9,564)	(13,923)	(23,487)	—	—	—	(23,487)
Intercompany advances, net	22,588	2,191	24,779	—	(24,779)	—	—
Other financing	—	—	—	—	(641)	—	(641)
	13,024	7,253	20,277	—	525	—	20,802
NET INCREASE IN CASH AND CASH EQUIVALENTS	169	3,454	3,623	—	538	—	4,161
Cash, beginning of period	8	682	690	—	—	—	690
Cash, end of period	$ 177	$ 4,136	$ 4,313	$ —	$ 538	$ —	$ 4,851

3. NOTES PAYABLE AND LONG-TERM DEBT

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

	JUNE 30,	
	1995	1994
	($ IN THOUSANDS)	
Senior notes, interest at 10.5% per annum payable semiannually in June and December, principal due June 2002	$ 90,000	$ —
Senior notes, interest at 12% per annum payable semiannually in March and September, mandatory redemption of $11,875,000 on each of March 1, 1998, 1999 and 2000, with remaining principal due March 2001	47,500	47,500
Discount on 12% Senior notes	(2,333)	(2,900)
Note payable to an individual and S.W. Energy, interest at 7% per annum, collateralized by producing oil and gas properties, paid in full in June 1995	—	1,216
Term note payable to Union Bank collateralized by CGDC, not guaranteed by the Company, interest at Union Bank's base rate (9% per annum at June 30, 1995), collateralized by CGDC's producing oil and gas properties, payable in monthly installments through April 2002	10,800	—
Term note payable to Union Bank, interest at Union Bank's base rate + an incremental rate (9% per annum at June 30, 1995), collateralized by CEX's producing oil and gas properties and guaranteed by the Company	10	10
Note payable to a vendor, interest at 1% per annum, collateralized by oil and gas tubulars, payments due 60 days from shipment of the tubulars	6,513	5,952
Note payable to a bank, interest at a referenced base rate + 1.75% (10.75% per annum at June 30, 1995), collateralized by office buildings, payments due in monthly installments through May 1998	686	751
Notes payable to various entities to acquire oil service equipment, interest varies from 7% to 11% per annum, collateralized by equipment, payments due in monthly installments through December 2000	2,162	2,126
Other, secured	230	482
Other, unsecured	179	317
Total notes payable and long-term debt	155,747	55,454
Less - current maturities	(9,993)	(7,576)
Notes payable and long-term debt, net of current maturities	$ 145,754	$ 47,878

The aggregate scheduled maturities of notes payable and long-term debt for the next five fiscal years ending June 30, 2000 and thereafter were as follows as of June 30, 1995 (in thousands of dollars):

1996	$ 9,993
1997	2,599
1998	12,373
1999	13,588
2000	12,954
After 2000	104,240
	$155,747

On May 25, 1995, the Company issued $90 million principal amount of the 10.5% Senior Notes due June 1, 2002 (See Note 2). The 10.5% Senior Notes are redeemable at the option of the Company at any time on or after June 1, 1999.

On March 31, 1994, the Company issued units consisting of an aggregate of $47.5 million principal amount of 12% Senior Notes due March 1, 2001 and Warrants to purchase 973,750 shares of the Company's Common Stock. (See Note 2.) The Warrants were valued at $3.04 million based on the market value of the Company's Common Stock at the date of issue ($3.125 per common share) and recorded as Common Stock Warrants and paid-in capital on the June 30, 1994 consolidated balance sheet. A bond discount was created as the difference between the combined value of the 12% Senior Notes and Warrants and the face value of the Units. The principal amount of the 12% Senior Notes, less the unamortized bond discount, is classified as long-term debt. As part of the offering, the Company issued 8,000 Units to TCW in exchange for preferred stock, warrants to purchase Common Stock and an overriding royalty interest.

The Company's wholly-owned subsidiary, CGDC, has a credit facility with Union Bank (the "Term Credit Facility"), with an outstanding balance of $10.8 million at June 30, 1995. Collateral for the Term Credit Facility is limited to CGDC's producing oil and gas properties. The Term Credit Facility has not been guaranteed by the Company or any of its other subsidiaries and is recourse only to the assets of CGDC. CGDC acquired producing oil and gas properties from CEX in December 1994 and June 1995 in exchange for $11.5 million in cash, using proceeds borrowed under this facility. CGDC has not guaranteed the payment of the Company's 12% or 10.5% Senior Notes, nor has the capital stock of CGDC been pledged to secure payment of such indebtedness. The terms of the Term Credit Facility prohibit the payment of dividends by CGDC.

In April 1993, the Company's subsidiary, CEX, entered into an oil and gas reserve-based reducing revolving credit facility (the "Revolving Credit Facility") with Union Bank. In conjunction with the issuance of both the 12% and 10.5% Senior Notes, the Revolving Credit Facility was amended and each time all but $10,000 of the balance was paid. The maturity date is May 31, 2000. Outstanding borrowings of up to 50% of the borrowing base will bear interest at Union Bank's reference rate; borrowings of 51% to 74% of the borrowing base will bear interest at the reference rate plus 0.25%; and borrowings of 75% or more of the borrowing base will bear interest at the reference rate plus 0.375%. Borrowings are secured by a first priority lien on substantially all of CEX's proved developed producing reserves, and are unconditionally guaranteed by the Company. At June 30, 1995 and 1994, there was a $10,000 outstanding balance under the Revolving Credit Facility.

The amount of credit available at any time under the Revolving Credit Facility is the lesser of the commitment amount or the borrowing base. The borrowing base is reduced each month by a specified amount. Both the borrowing base and the monthly reduction amount are redetermined by Union Bank each March 1 and September 1 and may be redetermined at any other time upon the request of CEX or Union Bank. CEX pays a redetermination service fee of $5,000 at each redetermination date. To the extent the amount outstanding at any time exceeds the borrowing base, CEX must reduce the amount outstanding or add additional collateral. At June 30, 1995, the commitment amount and the borrowing base under the Revolving Credit Facility was approximately $25 million, and the monthly reduction amount was $650,000. The Revolving Credit Facility contains customary financial covenants, limitations on indebtedness and liabilities, liens, prepayments of other indebtedness (including the 12% and 10.5% Senior

Notes), and loans, investments and guarantees by the Company and prohibits the payment of dividends on the Company's Common Stock.

In February 1994, pending litigation against the Company's subsidiary, COI, was settled. The agreement required COI to pay $1.25 million, of which $250,000 plus interest was paid in July 1994, with the balance payable over six years in equal quarterly installments including interest of 7%. Payment of the $1.25 million obligation was secured by mortgages on several of the Company's producing oil and gas properties. The note was paid in full in June 1995.

4. CONTINGENCIES AND COMMITMENTS

The Company is currently involved in various routine disputes incidental to its business operations and has included $320,000 in accrued liabilities at June 30, 1995 for potential future costs. 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 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 when considering the aforementioned provision.

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 generally expire June 30, 1998.

In November 1994, Dorothy Knox Duncan Hughes v. Chesapeake Operating, Inc. and Plains Marketing and Transportation, Inc., was filed in the District Court of Harris County, Texas. The plaintiff alleges, individually and as representative of a class of royalty owners under wells operated by the Company in Texas and Oklahoma, that the Company has underpaid such royalty owners because the monthly general and administrative fee it received from defendant Plains Marketing and Transportation, Inc. and other purchasers of crude oil had not been included in calculating royalties due. The plaintiff seeks a determination that a class exists; that the action is a proper class action; that plaintiff is the proper class representative; and that plaintiff and other members of the class are entitled to recover actual damages of an unspecified amount, attorney fees, exemplary damages (of an unspecified amount), court costs and interest. The Company intends to vigorously defend against plaintiff's claims. The Company's motion to transfer venue of the case to Fayette County was granted.

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 environmental issues or claims.

5. INCOME TAXES

As discussed in Note 1, the Company has adopted SFAS No. 109. The components of the income tax provision for each of the periods are as follows:

YEARS ENDED JUNE 30,	**1995**	1994	1993
		($ IN THOUSANDS)	
Current	$ —	$ —	$ —
Deferred	6,299	1,250	(99)
Total	$ 6,299	$ 1,250	$ (99)

The effective income tax rate differed from the computed "expected" federal income tax rate on earnings before income taxes for the following reasons:

YEARS ENDED JUNE 30,	**1995**	1994	1993
		($ IN THOUSANDS)	
Computed "expected" income tax provision (benefit)	$ 6,286	$ 1,753	$ (158)
Tax percentage depletion	(144)	(780)	—
Other	157	277	59
	$ 6,299	$ 1,250	$ (99)

Deferred income taxes are provided to reflect temporary differences in the basis of net assets for income tax and financial reporting purposes. The tax effected temporary differences and tax loss carryforwards which comprise deferred taxes are as follows:

YEARS ENDED JUNE 30,	1995	1994	1993
		($ IN THOUSANDS)	
Deferred tax liabilities:			
Acquisition, exploration and development costs and related depreciation, depletion and amortization	**$(31,220)**	$(15,872)	$(6,295)
Deferred tax assets:			
Net operating loss carryforwards	**23,414**	12,879	5,332
Percentage depletion carryforward	**526**	780	—
	23,940	13,659	5,332
Total Noncurrent	**$ (7,280)**	$ (2,213)	$ (963)

At June 30, 1995, the Company had regular tax net operating loss carryforwards of approximately $65 million and alternative minimum tax net operating loss carryfowards of approximately $3 million. These loss carryforward amounts will expire during the years 2007 through 2010. The Company also had a percentage depletion carryforward of approximately $1.5 million at June 30, 1995, 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 does not believe that an Ownership Change has occurred as of June 30, 1995.

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 June 30, 1995, 1994 and 1993 the Company had accounts receivable from these directors, shareholders and employees of $4.4 million, $1.7 million and $1.6 million, respectively. The aggregate average receivable balance due from these parties for the years ended June 30, 1995, 1994 and 1993 approximated $2.9 million, $1.3 million and $1.2 million, respectively.

During fiscal 1995, 1994 and 1993 the Company incurred legal expenses of $516,000, $631,000 and $723,000, respectively, for legal services provided by the law firm of which a director is a member.

From September 1993 to July 1994, the Company owned a 40% interest in, and was represented on the operating committee of, Wickford Energy Marketing, L.C. ("Wickford"), a limited liability company engaged in the marketing of oil and gas production. The remaining interests were owned by other oil and gas producers and marketers. In January 1994, the Company began to market a significant amount of its oil and gas production through Wickford. The Company sold its interest in Wickford to the other owners in July 1994. For fiscal 1995, sales to Wickford accounted for 28%, or $15.7 million, of the Company's total oil and gas sales revenue. Oil and gas sales receivables from Wickford were $1.6 million at June 30, 1995, and are reflected as oil and gas receivables on the accompanying consolidated balance sheet. The Company's former investment in Wickford was accounted for using the equity method.

7. EMPLOYEE BENEFIT PLANS

Effective October 1, 1989, the Company established a 401(K) profit sharing plan. On December 1, 1993, the Company amended the plan and established the Chesapeake Energy Savings and Incentive Plan (the "Savings and Incentive Plan"). Eligible employees may make voluntary contributions to the Savings and Incentive Plan which are matched by the Company up to 2.5% (5.0% as of July 1, 1995) of the employees' annual salary. The amount of employee contributions is limited as specified in the Savings and Incentive Plan. The Company may, at its discretion, make additional contributions to the Savings and Incentive Plan. The Company contributed $95,000, $70,000 and $44,000 to the Savings and Incentive Plan during the fiscal years ended June 30, 1995, 1994 and 1993, respectively.

8. MAJOR CUSTOMERS

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

YEAR		AMOUNT	PERCENT OF OIL AND GAS SALES
		($ IN THOUSANDS)	
1995	Aquila Southwest Pipeline Corporation	$18,548	33%
	Wickford Energy Marketing	$15,704	28%
	GPM Gas Corporation	$11,686	21%
1994	Wickford Energy Marketing, L.C.	$ 6,190	28%
	GPM Gas Corporation	$ 6,105	27%
	Plains Marketing and Transportation, Inc.	$ 2,659	12%
	Texaco Exploration & Production, Inc.	$ 2,249	10%
1993	Plains Marketing and Transportation, Inc.	$ 2,579	22%
	GPM Gas Corporation	$ 2,039	18%
	Mobil Oil Corporation	$ 1,775	15%
	Total Petroleum, Inc.	$ 1,380	12%
	Texaco Exploration & Production, Inc.	$ 1,368	12%

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

On March 31, 1994, the Company issued 12% Senior Notes and Warrants for 973,750 shares of the Company's Common Stock (see Note 2). The Warrants were valued at $3.04 million and are recorded as Common Stock Warrants and paid-in capital on the June 30, 1994 consolidated balance sheet. As part of the 12% Senior Note offering, the Company issued 8,000 Units to TCW in exchange for preferred stock, warrants to purchase Common Stock and an overriding royalty interest.

In February 1993, the Company completed an initial public offering of 4.6 million shares of its Common Stock at $6 per share. The total proceeds were $27.6 million with total net proceeds of approximately $25.2 million, of which $12.8 million was used to reduce indebtedness, and the balance was used to fund operations and as working capital.

On December 4, 1992, the Company issued to TCW 576,923 shares of its convertible preferred stock in exchange for a $7.5 million reduction in the Company's debt to TCW. Pro forma per share data assuming full conversion of the convertible preferred stock to common shares is not provided herein as the results are antidilutive. The convertible preferred stock was acquired by the Company in connection with the issuance of the 12% Senior Notes (see Note 2) and has been retired.

In connection with an amendment to a credit agreement with TCW on July 2, 1992, the Company issued to TCW a stock warrant granting TCW the right to purchase up to 624,002 shares of Common Stock at a price of $2.09 per share. The warrant was acquired by the Company in connection with the issuance of the 12% Senior Notes (see Note 2).

As part of a loan transaction with Belco (see Note 3), Belco received warrants to purchase a maximum of 360,000 shares of Common Stock at an exercise price of $4.80 per share. All such warrants have been exercised.

A 1.8-for-1 stock split of the Common Stock in January 1993 and a 2-for-1 stock split of the Common Stock in December 1994 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 836,000 shares. The maximum period for exercise of an option shall not be more than ten years (or five years for an optionee who owns more than 10% of the Common Stock) from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant (or 110% of such value for an optionee who owns more than 10% of the Common Stock). Options granted become exercisable at dates determined by the Stock

Option Committee of the Board of Directors. No options may 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 696,000 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the Stock Option Committee of the Board of Directors. No options may be granted under the NSO Plan after December 10, 2002.

Under the Company's 1994 Stock Option Plan (the "1994 Plan"), incentive and nonqualified stock options to purchase Common Stock may be granted to employees of the Company and its subsidiaries. Subject to any adjustment as provided by the 1994 Plan, the aggregate number of shares which may be issued and sold may not exceed 1,085,980 shares. The maximum period for exercise of an option may not be more than ten years from the date of grant, and the exercise price may not be less than the fair market value of the shares underlying the options on the date of grant. Options granted become exercisable at dates determined by the Stock Option Committee of the Board of Directors. No options may be granted under the 1994 Plan after December 16, 2004.

	# OF OPTIONS	OPTION PRICES
Options granted	393,680	$ 2.50 - $ 6.00
Options exercised	—	—
Options terminated	—	—
Options outstanding at June 30, 1993	393,680	$ 2.50 - $ 6.00
Options granted	729,000	$ 2.50 - $ 3.85
Options exercised	—	—
Options terminated	(4,160)	$ 2.50 - $ 3.00
Options outstanding at June 30, 1994	1,118,520	$ 2.50 - $ 6.00
Options granted	707,900	$10.13 - $22.13
Options exercised	(286,385)	$ 2.50 - $ 6.00
Options terminated	(22,570)	$ 2.50 - $10.13
Options outstanding at June 30, 1995	1,517,465	$ 2.50 - $22.13

The exercise of 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 fiscal 1995, $1,229,000 was credited to additional paid-in capital with respect to such tax benefits.

10. 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:

YEARS ENDED JUNE 30,	**1995**	1994	1993
		($ IN THOUSANDS)	
Oil and gas properties:			
Proved	**$ 165,302**	$ 83,170	$ 56,181
Unproved	**27,474**	3,729	2,411
Total	**192,776**	86,899	58,592
Less accumulated depreciation, depletion and amortization	**(41,821)**	(16,417)	$(8,276)
Net capitalized costs	**$ 150,955**	$ 70,482	$ 50,316

Unproved properties not subject to amortization at June 30, 1995 and 1994, consist mainly of lease acquisition costs. The Company capitalized approximately $1,574,000, $356,000 and $192,000 of interest during the years ended June 30, 1995, 1994 and 1993 on significant investments in unproved properties that are not being currently depreciated, depleted, or amortized and on which exploration or development activities are in progress. 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:

YEARS ENDED JUNE 30,	**1995**	1994	1993
		($ IN THOUSANDS)	
Development costs	**$ 72,794**	$ 21,812	$ 12,263
Exploration costs	**14,129**	5,358	1,123
Acquisition costs:			
Unproved properties	**24,437**	3,305	1,364
Proved properties	**6,896**	3,320	976
Capitalized internal costs	**2,729**	2,110	1,080
Proceeds from sale of leasehold, equipment and other	**(15,107)**	(7,598)	(3,943)
Total	**$ 105,878**	$ 28,307	$ 12,863

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 years ended June 30, 1995, 1994 and 1993, 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.

YEARS ENDED JUNE 30,	**1995**	1994	1993
		($ IN THOUSANDS)	
Oil and gas sales	**$ 56,983**	$ 22,404	$ 11,602
Production costs (a)	**(4,256)**	(3,647)	(2,890)
Depletion and depreciation	**(25,410)**	(8,141)	(4,184)
Imputed income tax provision (b)	**(9,561)**	(3,610)	(1,540)
Results of operations from oil and gas producing activities	**$ 17,756**	$ 7,006	$ 2,988

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

(b)The imputed income tax provision is hypothetical and determined without regard to the Company's deduction for general and administrative expenses, interest costs and other income tax credits and deductions.

OIL AND GAS RESERVE QUANTITIES (UNAUDITED)

The reserve information presented below is based upon reports prepared by the independent petroleum engineering firm of Williamson Petroleum Consultants, Inc. ("Williamson") as of June 30, 1995, 1994 and 1993 and the Company's petroleum engineers as of June 30, 1995. The reserves evaluated internally by the Company constituted one-half of one percent (0.5%) of total proved reserves as of June 30, 1995. 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, as future information becomes available.

Proved oil and gas reserves represent the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of changes in estimated reserves of the Company based upon the reports prepared by Williamson for 1995, 1994 and 1993, along with those prepared by the Company's petroleum engineers for 1995:

	JUNE 30, 1995		JUNE 30, 1994		JUNE 30, 1993	
	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)	OIL (MBBL)	GAS (MMCF)
Proved reserves, beginning of year	**4,154**	**117,066**	9,622	79,763	11,147	68,618
Extensions, discoveries and other additions	**2,345**	**129,444**	2,335	82,965	1,576	15,078
Revisions of previous estimate	**(244)**	**(9,588)**	(868)	(5,523)	(2,427)	3,529
Production	**(1,139)**	**(25,114)**	(537)	(6,927)	(276)	(2,677)
Sale of reserves-in-place	**—**	**—**	(6,398)	(33,212)	(398)	(4,789)
Purchase of undeveloped reserves-in-place	**—**	**—**	—	—	—	4
Proved reserves, end of year	**5,116**	**211,808**	4,154	117,066	9,622	79,763
Proved developed reserves, end of year	**1,973**	**77,764**	1,313	30,445	830	11,893

In October 1993, the Company entered into a joint development agreement covering a 20,000 gross acre development area in the Fayette County portion of the Giddings Field in southern Texas. The Company's ownership interests in the proved undeveloped properties covered by the joint development agreement were significantly less than those used in the June 30, 1993 reserve report. The impact of the reduced ownership percentages is reflected as sales of reserves in place in fiscal 1994 in the preceding table.

The revisions in the Company's estimated quantities of oil and gas are attributable to revised estimates by Williamson. At the end of fiscal 1993, Williamson significantly reduced the estimated quantities of oil and increased the estimated quantities of gas attributable to the Company's interests in the Giddings Field in Texas.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED)

SFAS No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and gas to be produced. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. Estimated future income taxes are computed using current statutory income tax rates including consideration for the current tax basis of the properties and related carryforwards, giving effect to permanent differences and tax credits. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in SFAS No. 69:

YEARS ENDED JUNE 30,	**1995**	1994	1993
	($ IN THOUSANDS)		
Future cash inflows	**$ 427,377**	$ 307,600	$ 374,190
Future production costs	**(75,927)**	(50,765)	(72,691)
Future development costs	**(76,543)**	(47,040)	(86,383)
Future income tax provision	**(46,537)**	(36,847)	(37,248)
Future net cash flows	**228,370**	172,948	177,868
Less effect of a 10% discount factor	**(69,359)**	(54,340)	(58,124)
Standardized measure of discounted future net cash flows	**$ 159,011**	$ 118,608	$ 119,744

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

YEARS ENDED JUNE 30,	1995	1994	1993
	($ IN THOUSANDS)		
Standardized measure, beginning of year	**$ 118,608**	$ 119,744	$ 125,752
Sales of oil and gas produced, net of production costs	**(52,727)**	(18,757)	(8,712)
Net changes in prices and production costs	**(25,574)**	(10,795)	(25,935)
Extensions and discoveries, net of production and development costs	**93,969**	99,175	21,579
Changes in future development costs	**3,406**	(2,855)	(4,154)
Development costs incurred during the period that reduced future development costs	**23,678**	9,855	7,233
Revisions of previous quantity estimates	**(11,204)**	(13,107)	(13,089)
Purchase of undeveloped reserves-in-place	—	—	(3)
Sales of reserves in-place	—	(66,372)	(10,114)
Accretion of discount	**14,126**	14,166	16,453
Net change in income taxes	**(6,486)**	(720)	16,556
Changes in production rates and other	**1,215**	(11,726)	(5,822)
Standardized measure, end of year	**$ 159,011**	$ 118,608	$ 119,744

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized unaudited quarterly financial data for 1995 and 1994 are as follows ($ in thousands except per share data):

	QUARTERS ENDED			
	SEPTEMBER 30, 1994	DECEMBER 31, 1994	MARCH 31, 1995	JUNE 30, 1995
Net sales	$13,042	$14,186	$15,788	$22,803
Gross profit	4,559	5,805	4,997	7,702
Net income	2,336	3,248	2,305	3,772
Income per share	.20	.26	.19	.30

	QUARTERS ENDED			
	SEPTEMBER 30, 1993	DECEMBER 31, 1993	MARCH 31, 1994	JUNE 30, 1994
Net sales	$ 5,366	$ 6,250	$ 6,606	$10,621
Gross profit	650	841	716	4,643
Net income	285	517	340	2,763
Income per share	.01	.03	.03	.24

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