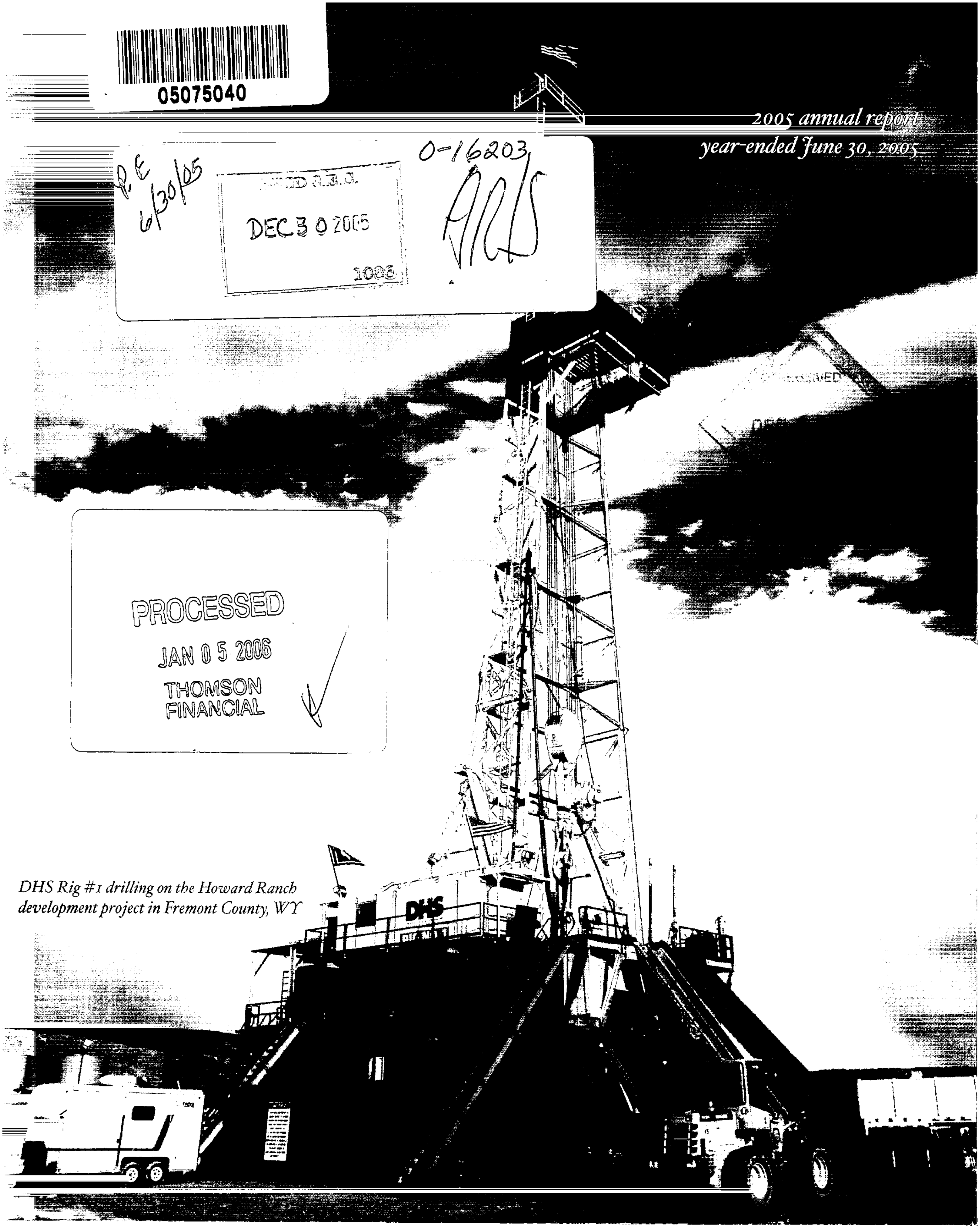
2005 annual report
year-ended June 30, 2005



DHS Rig #1 drilling on the Howard Ranch development project in Fremont County, WY

The fiscal year ended June 30, 2005 was an historic and important one for your Company. During fiscal year 2005, we accomplished a number of objectives that position Delta for substantial growth in the future. Most importantly, we identified and acquired a substantial portfolio of oil and gas leasehold assets that provide the Company with a multi-year inventory of repeatable development opportunities with low geologic risk. As of this date, Delta's portfolio includes over 1,000,000 acres of leasehold in our core areas of development, which include the Rocky Mountain states, eastern Washington and the gulf coast of Texas.

In addition to the significant expansion in our drilling inventory, we have focused on other areas that are vital to Delta's continued growth and development. During fiscal year 2005, the Company's staff more than doubled to a current level of over 100 highly experienced employees, many of whom have the technical expertise necessary to implement and manage a more aggressive drilling program. We assured full-time access to our own drilling rigs through the formation of DHS Drilling Company (DHS), which now owns 11 rigs with depth capabilities ranging from 7,500' to 21,000'. DHS also owns a trucking company that is able to transport drilling rigs from one well location to the next in a timely manner. Finally, we successfully accessed the capital markets to obtain the financing necessary to increase capital expenditures in the upcoming year. Our drilling capital expenditures are expected to approximate $150 million in calendar 2006, which represents a 55% increase over such expenditures in fiscal year 2005 and a 35% increase over calendar year 2005.

Other highlights and accomplishments for fiscal year 2005 include the following:

- Our production increased 84% to 14.0 billion cubic feet equivalents (Bcfe), compared with 7.6 Bcfe in FY2004.
- Our proved reserves expanded 33% to 224 Bcfe, versus 168 Bcfe at the end of the previous fiscal year.
- Our revenue rose 160% to $94.7 million, compared with $36.4 million in FY2004.
- Our net income increased 196% to $15.1 million, or $0.36 per diluted share, from $5.1 million, or $0.17 per diluted share, in FY2004.
- Our drilling capital expenditures more than tripled, to $95 million, compared with $25 million in FY2004.
- We issued $150 million in 10-year senior unsecured notes, thereby providing liquidity and fixing the costs associated with the majority of our debt at attractive interest rates.

Consistent with management's commitment to enhance shareholder value, a number of accomplishments are worthy of note since the end of FY2005, including:

- The sale of approximately $35 million in non-core assets in transactions that have strengthened the liquidity of our balance sheet and allowed the Company to focus on core areas of development.
- The acquisition of interests that consolidated our ownership in the Columbia River Basin, an exciting frontier project in eastern Washington that is currently being drilled and where we have nearly 400,000 net acres under lease.
- The acquisition of an interest in Piceance Gas Resources, a special purpose entity that is actively developing the Garden Gulch Field area in the Piceance Basin in western Colorado.
- The issuance of 5.4 million shares of common stock in a private placement equity offering that raised $100 million to fund the above-described acquisitions and to accelerate our drilling program.
- The entry into a merger agreement with Castle Energy Corporation that should close in early 2006, subsequent to approval by Castle shareholders. This transaction will provide approximately $25 million in liquidity and increase our producing reserves by 8.4 Bcfe.
- The receipt of a ruling from the United States Court of Federal Claims in Washington D.C., wherein the federal government has been ordered to reimburse Delta and other plaintiffs over $1.1 billion for breach of contract claims related to our Offshore California properties. Delta's net share of the award exceeds $120 million. Although subject to further action by the court and a possible appeal, this ruling represents a significant and important step in resolving what has been long-term litigation.

To conform with traditional financial reporting schedules within the oil and gas industry, we will change to a fiscal year ending December 31 at the end of 2005 and will report on a calendar year basis in the future.

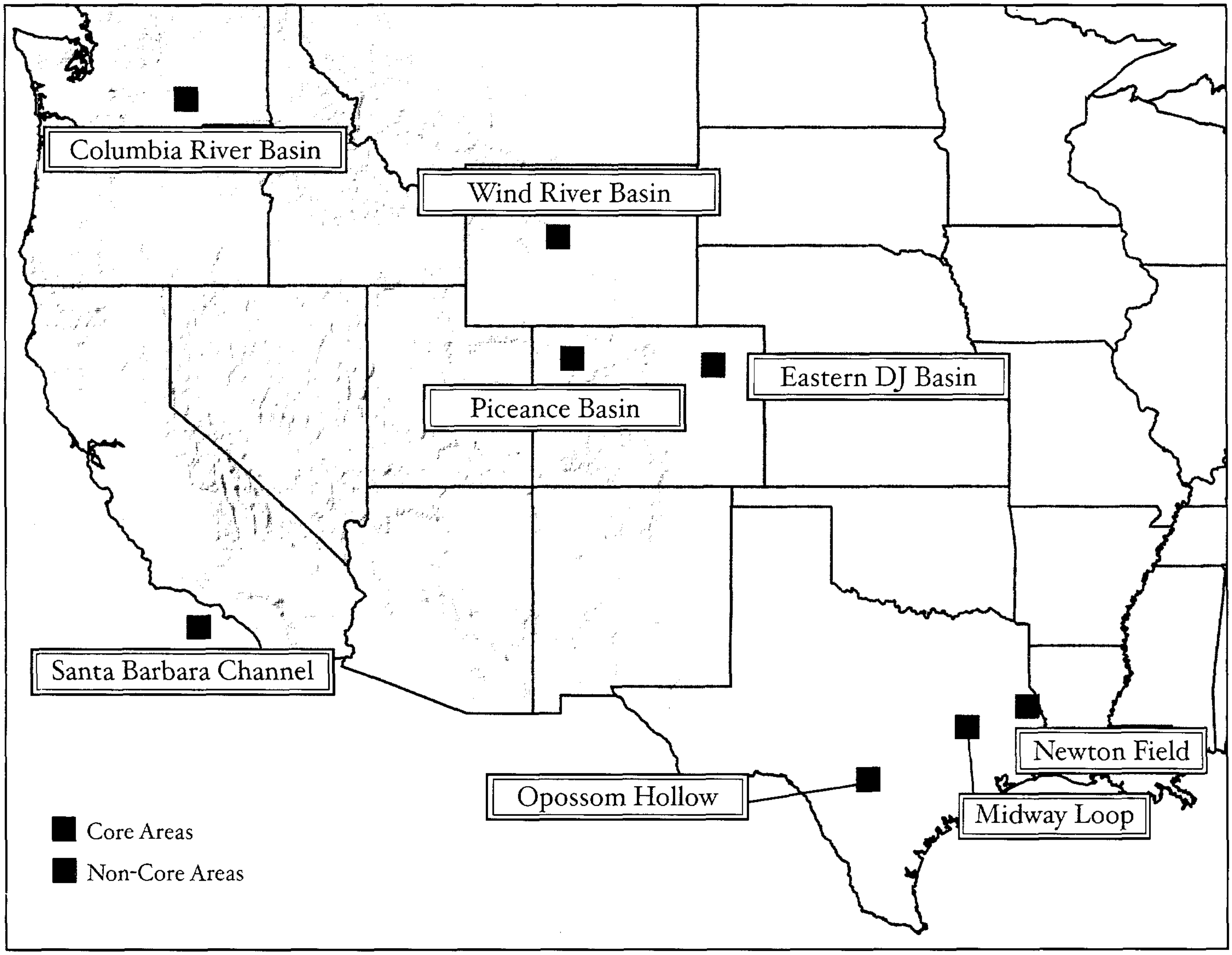
We believe that during 2006 we will experience meaningful gains in production and growth in proven reserves that will be the direct result of the effort that has been put forth thus far. We appreciate the loyalty and commitment of our employees, our board of directors and our shareholders as we approach and look forward to the prospects of the coming year.

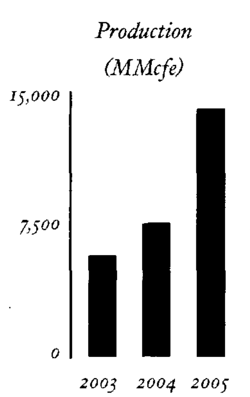
Very truly yours,

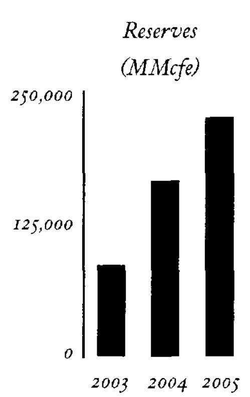
Roger A. Parker
Chairman, Chief Executive Officer and President

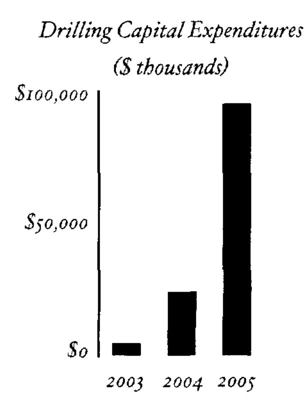
John R. Wallace
Executive Vice President and Chief Operating Officer

December 15, 2005


Columbia River Basin
Wind River Basin
Piceance Basin
Eastern DJ Basin
Santa Barbara Channel
Newton Field
Opossom Hollow
Midway Loop
Core Areas
Non-Core Areas


Production
(MMcfe)
15,000
7,500
0
2003
2004
2005


Reserves
(MMcfe)
250,000
125,000
0
2003
2004
2005


Drilling Capital Expenditures
($ thousands)
$100,000
$50,000
$0
2003
2004
2005

Financial Results
(In thousands except per share amounts)

		Years Ended June 30,				
		2005		*2004*		*2003*
Total Revenue	$	94,707	$	36,367	$	20,718
Operating Expenses	$	75,998	$	32,500	$	19,223
Operating Income	$	18,709	$	3,867	$	1,495
Other Income (Expense)	$	(7,433)	$	(1,570)	$	(1,736)
Income (Loss) from Continuing Operations	$	11,276	$	2,297	$	(241)
Income Tax Expense (Benefit)	$	(3,325)	$	-	$	-
Net Earnings (Loss) from Continuing Operations	$	14,601	$	2,297	$	(241)
Net Income	$	15,050	$	5,056	$	1,257
Net Income Per Share-Basic	$	0.37	$	0.19	$	0.05
Net Income Per Share-Diluted	$	0.36	$	0.17	$	0.05
Current Assets	$	27,034	$	14,953	$	8,667
Net Property and Equipment	$	473,550	$	256,339	$	77,818
Total Long Term Assets	$	12,399	$	1,412	$	362
Total Assets	$	512,983	$	272,704	$	86,847
Current Liabilities	$	54,150	$	14,290	$	15,901
Long-Term Debt	$	216,001	$	69,630	$	22,175
Other Liabilities	$	6,595	$	2,542	$	868
Stockholders' Equity	$	221,623	$	185,997	$	47,903
Total Liabilities and Stockholders' Equity	$	512,983	$	272,704	$	86,847

Oil and Gas Reserves and Operations		*2005*		*June 30, 2004*		*2003*		*3-Yr Weighted Avg*
Proved Reserves:								
Oil, Condensate and NGL's (MBbls)		13,866		13,205		5,749		
Natural Gas (MMcf)		141,041		88,479		55,200		
Natural Gas Equivalents (MMcfe)		224,237		167,709		89,694		
Percent Developed		52%		58%		55%		
SEC PV-10 Before Tax (000)	$	683,729	$	379,107	$	139,891		
Finding Cost ($/Mcfe, all inclusive)	$	2.81	$	2.03	$	0.77	$	2.19
Annual Production								
Oil, Condensate and NGL's (MBbls)		1,055		748		479		
Natural Gas (MMcf)		7,675		3,110		2,938		
Natural Gas Equivalents (MMcfe)		14,005		7,598		5,812		
Reserve/Production Ratio (Years)		16.0		22.1		15.4		
Production Replacement %		565%		1264%		404%		724%

DESCRIPTION OF BUSINESS

General

Delta Petroleum Corporation ("Delta," "we" or "us") is a Denver, Colorado based independent energy company engaged primarily in the exploration for, and the acquisition, development, production, and sale of, natural gas and crude oil. Our core areas of operation are the Rocky Mountain and Gulf Coast regions, which comprise the majority of our proved reserves, production and long-term growth prospects. We have a significant drilling inventory that consists of proved and unproved locations, the majority of which are located in our Rocky Mountain development projects. We expect that our drilling efforts and capital expenditures will focus increasingly on the Rockies, where approximately two-thirds of our fiscal 2006 capital budget is allocated and three-fourths of our undeveloped acreage is located. We retain a high degree of operational control over our asset base, with an average working interest in excess of 90% as of June 30, 2005. This provides us with controlling interests in a multi-year inventory of drilling locations, positioning us for continued reserve and production growth through our drilling operations. We also currently have an ownership interest in a drilling company, providing the benefit of a preferential right to use its drilling rigs in the Rocky Mountain region which allows us to have a priority to drill our wells. We concentrate our exploration and development efforts in fields where we can apply our technical exploration and development expertise, and where we have accumulated significant operational control and experience.

On September 14, 2005, our Board of Directors made the decision to change our year end to December 31.

Our principal executive offices are located at 370 17th Street, Suite 4300, Denver, Colorado 80202. Our telephone number is (303) 293-9133.

The following table presents information regarding our primary oil and gas areas of operations as of June 30, 2005:

Areas of Operations	Proved Reserves (Bcfe) (1)	% Natural Gas	% Proved Developed	2005 Production (MMcfe/d) (2)
Rocky Mountain Region	39.4	90.2%	35.3%	6.7
Gulf Coast Region	121.6	50.1%	49.8%	17.2
Offshore California	9.0	-%	39.1%	2.6
Other	54.3	82.1%	69.5%	11.9
Total	224.3	62.9%	51.6%	38.4

(1) Bcfe means billion cubic feet of gas equivalent
(2) MMcfe/d means million cubic feet of gas equivalent per day

We intend to develop our primary areas of operations. For the six months ending December 31, 2005, we estimate our exploration and development capital budget to range between $50.0 - $65.0 million.

We have authorized capital of 3,000,000 shares of $.10 par value preferred stock, of which no shares were issued, and 300,000,000 shares of $.01 par value common stock, of which 42,017,000 shares were issued and outstanding as of June 30, 2005. We have outstanding options which were granted to our officers, employees and directors under our incentive plans, to purchase up to 3,501,000 shares of common stock at prices ranging from $1.13 to $15.46 per share.

At June 30, 2005, we owned 4,277,977 shares of common stock of Amber Resources Company ("Amber"), representing 91.68% of the outstanding common stock of Amber. Amber is a public company (registered under the Securities Exchange Act of 1934) which owns non-operated working interests in undeveloped leases offshore California, near Santa Barbara. We entered into an agreement with Amber effective October 1, 1998 which provides, in part, for the sharing of the management between the two companies and allocation of expenses related thereto.

Operations

During the year ended June 30, 2005, we were primarily engaged in only one industry, namely the acquisition, exploration, development, and production of oil and gas properties and related business activities. Our oil and gas operations have been comprised primarily of production of oil and gas, drilling exploratory and development wells and related operations and acquiring and selling oil and gas properties. Directly or through wholly-owned subsidiaries and through Amber, we currently own producing and non-producing oil and gas interests, undeveloped leasehold interests and related assets in fifteen (15) states, interests in a producing Federal unit offshore California and undeveloped offshore Federal leases near Santa Barbara, California. We intend to continue our emphasis on the drilling of exploratory and development wells primarily in Alabama, Colorado, Louisiana, New Mexico, Texas, Wyoming, and offshore California.

We intend to drill on some of our leases (presently owned or subsequently acquired); we may farm out or sell all or part of some of the leases to others; and/or we may participate in joint venture arrangements to develop certain other leases. Such transactions may be structured in a number of different manners that are in use in the oil and gas industry. Each such transaction is likely to be individually negotiated and no standard terms may be predicted.

We have oil and gas leases with governmental entities and other third parties who enter into oil and gas leases or assignments with us in the regular course of our business. We have no material patents, licenses, franchises or concessions that we consider significant to our oil and gas operations. The nature of our business is such that it is not seasonal, we do not engage in any research and development activities and we do not maintain or require a substantial amount of products, customer orders or inventory. Our oil and gas operations are not subject to renegotiations of profits or termination of contracts at the election of the federal government. We operate the majority of our properties and control the costs incurred. We have never been a party to any bankruptcy, receivership, reorganization or similar proceeding.

We currently own a 49.5% ownership interest in DHS Drilling Company ("DHS"), an affiliated Colorado corporation that is headquartered in Casper, Wyoming. DHS currently has seven drilling rigs in operation that have depth ratings of approximately 7,500 to 20,000 feet. Three additional rigs are in the process of being acquired or assembled by DHS and are currently expected to become operational during the fall of 2005. We have the right to use all of the rigs on a priority basis, although approximately half will initially work for third party operators. At the outset, all of the rigs will operate in the Rocky Mountain and Columbia River basins.

DIRECTORS AND EXECUTIVE OFFICERS

The following information with respect to Executive Officers and Directors is furnished pursuant to Item 401(a) of Regulation S-K.

Name	Age	Positions	Period of Service
Roger A. Parker	43	President, Chief Executive Officer and a Director	May 1987 to Present
Kevin K. Nanke	40	Treasurer and Chief Financial Officer	December 1999 to Present
John R. Wallace	44	Executive V.P., Exploration and Chief Operating Officer	October 2003 to Present
Kevin R. Collins	48	Director	March 2005 to Present
Jerrie F. Eckelberger	61	Director	September 1996 to Present
Aleron H. Larson, Jr.	60	Director	May 1987 to Present
Russell S. Lewis	50	Director	June 2002 to Present
Jordan R. Smith	70	Director	October 2004 to Present
Neal A. Stanley	58	Director	October 2004 to Present
James P. Van Blarcom	43	Director	July 2005 to Present
James B. Wallace	75	Director	November 2001 to Present

The following is biographical information as to the business experience of each of our current officers and directors.

Roger A. Parker has been our President and a Director since May of 1987 and Chief Executive Officer since April of 2002. He was named Chairman of the Board on July 1, 2005. Since April 1, 2005, he has also served as a Director of DHS Drilling Company. Mr. Parker also serves as President, Chief Executive Officer and Director of Amber Resources. He received a Bachelor of Science in Mineral Land Management from the University of Colorado in 1983. He is a member of the Rocky Mountain Oil and Gas Association and is a board member of the Independent Producers Association of the Mountain States (IPAMS). He also serves on other boards, including Community Banks of Colorado.

Kevin K. Nanke, Treasurer and Chief Financial Officer, joined Delta in April 1995. Since April 1, 2005 he has also served as Chief Financial Officer, Treasurer and Director of DHS Drilling Company. Since 1989, he has been involved in public and private accounting with the oil and gas industry. Mr. Nanke received a Bachelor of Arts in Accounting from the University of Northern Iowa in 1989. Prior to working with us, he was employed by KPMG LLP. He is a member of the Colorado Society of CPA's and the Council of Petroleum Accounting Society.

John R. Wallace, Executive Vice President, Exploration and Chief Operating Officer, joined Delta in October 2003. Since April 1, 2005 he has also served as Executive Vice President and Director of DHS Drilling Company. Mr. Wallace was Vice President of Exploration and Acquisitions for United States Exploration, Inc. ("USX"), a publicly-held oil and gas exploration company, from May 1998 to October 2003, when he became employed by Delta. For more than five years prior to joining USX, Mr. Wallace was President of The Esperanza Corporation, a privately held oil and gas acquisition company, and Vice President of Dual Resources, Inc., a privately held oil and gas exploration company. Esperanza effected more than 25 acquisitions of producing properties throughout the United States. In addition, Esperanza formed and administered royalty programs for private investors, primarily in the Rocky Mountain region, and has participated in a number of international exploration projects. Dual Resources is in the business of engineering and selling exploration prospects, several of which have resulted in new field discoveries. Mr. Wallace is the son of John B. Wallace, a Director of the Company.

Kevin R. Collins was most recently Executive Vice President and Chief Financial Officer of Evergreen Resources, Inc., having served in various management capacities with that company from 1995 until 2004. Evergreen Resources was acquired by Pioneer Natural Resources in September 2004. Mr. Collins became a Certified Public Accountant in 1983 and has over 13 years of public accounting experience. He has served as Vice President and a Board Member of the Colorado Oil and Gas Association, President of the Denver Chapter of the Institute of Management Accountants, Director of Pegasus Technologies, Inc. and Board Member and Chairman of the Finance Committee of Independent Petroleum Association of Mountain States. He received his B.S. degree in Business Administration and Accounting from the University of Arizona.

Jerrie F. Eckelberger is an investor, real estate developer and attorney who has practiced law in the State of Colorado since 1971. He graduated from Northwestern University with a Bachelor of Arts degree in 1966 and received his Juris Doctor degree in 1971 from the University of Colorado School of Law. From 1972 to 1975, Mr. Eckelberger was a staff attorney with the Eighteenth Judicial District Attorney's Office in Colorado. From 1975 to present, Mr. Eckelberger has been engaged in the private practice of law and is presently a member of the law firm of Eckelberger & Jackson, LLC. Mr. Eckelberger previously served as an officer, director and corporate counsel for Roxborough Development Corporation. Since March, 1996, Mr. Eckelberger has engaged in the investment and development of Colorado real estate through several private companies in which he is a principal.

Aleron H. Larson, Jr. has operated as an independent in the oil and gas industry individually and through public and private ventures since 1978. Mr. Larson served as Chairman of the Board, Secretary and Director of Delta, as well as Amber, until his retirement on July 1, 2005, at which time he resigned as Chairman of the Board and as an executive officer of the Company. Mr. Larson practiced law in Breckenridge, Colorado from 1971 until 1974. During this time he was a member of a law firm, Larson & Batchellor, engaged primarily in real estate law, land use litigation, land planning and municipal law. In 1974, he formed Larson & Larson, P.C., and was engaged primarily in areas of law relating to securities, real estate, and oil and gas until 1978. Mr. Larson received a Bachelor of Arts degree in Business Administration from the University of Texas at El Paso in 1967 and a Juris Doctor degree from the University of Colorado in 1970.

Russell S. Lewis is President and CEO of Lewis Capital, LLC which makes private investments in, and provides general business and M&A consulting services to, growth-oriented firms. He has been a member of the board of Delta Petroleum Corporation since June 2002. From February 2002 until January 2005 Mr. Lewis served as Executive Vice President and General Manager of VeriSign Name and Directory Services (VRSN) Group, which managed a significant portion of the internet's critical .com and .net addressing infrastructure. For the preceding 15 years Mr. Lewis managed a wireless transportation systems integration company. Previously Mr. Lewis managed an oil and gas exploration subsidiary of a publicly traded utility and was Vice President of EF Hutton in its Municipal Finance group. Mr. Lewis also serves on the board of directors of Castle Energy Corporation (NASDAQ: CECX) and Advanced Aerations Systems, a privately held firm engaged in the subsurface soil treatment. Mr. Lewis has a BA degree in Economics from Haverford College and an MBA from the Harvard School of Business.

Jordan R. Smith is President of Ramshorn Investments, Inc., a wholly owned subsidiary of Nabors Drilling USA LP, where he is responsible for drilling and development projects in a number of producing basins in the United States. He has served in such capacity for more than the past five years. Mr. Smith has served on the Board of the University of Wyoming Foundation and the Board of the Domestic Petroleum Council, and is also Founder and Chairman of the American Junior Golf Association. Mr. Smith received Bachelors and Masters degrees in geology from the University of Wyoming in 1956 and 1957, respectively.

Neal A. Stanley founded Teton Oil & Gas Corporation in Denver, Colorado and has served as President since June 2003. From 1996 to June 2003, he was Senior Vice President – Western Region for Forest Oil Corporation. Mr.

Stanley has approximately thirty years of experience in the oil and gas business. Since 1995, he has been a member of the Executive Committee of the Independent Petroleum Association of Mountain States, and served as its President from 1999 to 2001. Mr. Stanley received a B.S. degree in Mechanical Engineering from the University of Oklahoma in 1975.

James P. Van Blarcom has been Managing Director of The Payne Castle Group, LLC, which has provided sales solutions business development and government affairs services in the cable, high-speed internet and communications industries since 2004. From 1998 to 2004, he was employed by Comcast Cable Communications Management, LLC, a division of Comcast Corporation, where he served as National Telecommunications Manager, Corporate Telecommunications Manager, and finally as Commercial Development Manager, Comcast High-Speed Internet. Mr. Van Blarcom received a B.A. degree in History from Hobart College in 1984.

James B. Wallace has been involved in the oil and gas business for over 40 years and has been a partner of Brownlie, Wallace, Armstrong and Bander Exploration in Denver, Colorado since 1992. From 1980 to 1992 he was Chairman of the Board and Chief Executive Officer of BWAB Incorporated. Mr. Wallace currently serves as a member of the Board of Directors and formerly served as the Chairman of Tom Brown, Inc., an oil and gas exploration company then listed on the New York Stock Exchange. He received a B.S. Degree in Business Administration from the University of Southern California in 1951. James B. Wallace is the father of John R. Wallace, the Executive Vice President, Exploration and Chief Operating Officer of Delta.

At the present time Messrs. Collins, Eckelberger, Lewis, Smith and Stanley serve as the Audit Committee; Messrs. Eckelberger, Collins, Lewis, Smith and Stanley serve as the Compensation Committee; and Messrs. Smith, Collins, Eckelberger, Lewis and Stanley serve as the Nominating & Governance Committee.

All directors will hold office until the next annual meeting of shareholders.

All of our officers will hold office until the next annual directors' meeting. There is no arrangement or understanding among or between any such officers or any persons pursuant to which such officer is to be selected as one of our officers.

MARKET FOR COMMON STOCK AND RELATED STOCKHOLDER MATTERS

Market Information

Delta's common stock currently trades under the symbol "DPTR" on the NASDAQ National Market. The following quotations reflect inter-dealer high and low sales prices, without retail mark-up, mark-down or commission and may not represent actual transactions.

Quarter Ended	High	Low
September 30, 2003	$ 5.73	$ 4.12
December 31, 2003	6.30	4.75
March 31, 2004	11.19	6.04
June 30, 2004	15.93	10.00
September 30, 2004	$15.47	$10.01
December 31, 2004	16.11	12.67
March 31, 2005	17.07	12.87
June 30, 2005	14.95	8.99

Approximate Number of Holders of Common Stock

The number of holders of record of our common stock at September 12, 2005 was approximately 800 which does not include an estimated 2,500 additional holders whose stock is held in "street name."

Dividends

We have not paid dividends on our common stock and we do not expect to do so in the foreseeable future.

SELECTED FINANCIAL DATA

The following selected financial information should be read in conjunction with our financial statements and the accompanying notes.

	Years Ended June 30,				
	2005	2004	2003	2002	2001
	(In thousands, except per share amounts)				
Total Revenues	$ 94,707	$ 36,367	$ 20,718	$ 8,052	$ 12,712
Income from Continuing Operations	$ 11,276	$ 2,297	$ (241)	$ (6,156)	$ 345
Net Income (Loss)	$ 15,050	$ 5,056	$ 1,257	$ (6,253)	$ 345
Income/(Loss) Per Common Share					
Basic	$ .37	$ .19	$ .05	$ (.49)	$ .03
Diluted	$ .36	$ .17	$ .05	$ (.49)	$ .03
Total Assets	$ 512,983	$ 272,704	$ 86,847	$ 74,077	$ 29,832
Total Liabilities	$ 276,746	$ 86,462	$ 38,944	$ 29,161	$ 11,551
Minority Interest	$ 14,614	$ 245	$ -	$ -	$ -
Stockholders' Equity	$ 221,623	$ 185,997	$ 47,903	$ 44,916	$ 18,281
Total Long-Term Liabilities	$ 226,073	$ 72,386	$ 33,082	$ 24,939	$ 9,434

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Fiscal 2005 Accomplishments

- Increased reserves to 224.3 Bcfe at June 30, 2005, an increase of 33.7% compared to fiscal 2004.
- Increased production to 14.0 Bcfe for the year ended June 30, 2005, an increase of 84.3% compared to the same period in 2004.
- Issued $150.0 million in Senior Notes, unsecured, which mature in 2015.
- Successfully acquired 41.6 Bcfe of proven reserves for $69.0 million.
- Formed DHS Drilling Company which now has a total of ten drilling rigs with depth ratings from 7,500 – 20,000 feet.

The following discussion and analysis relates to items that have affected our results of operations for the three years ended June 30, 2005, 2004 and 2003. This analysis should be read in conjunction with our consolidated financial statements and accompanying notes included in this Form 10-K.

Results of Operations

Fiscal 2005 Compared to Fiscal 2004

Net Income. Net income increased $10.0 million to $15.1 million or $.36 per diluted common share for fiscal 2005, an increase of 198% as compared to $5.1 million or $.17 per diluted common share for fiscal 2004. This increase was primarily due to a 91% increase in production relating to the Alpine acquisition completed during fiscal 2004, the Manti acquisition completed during fiscal 2005 and the development of our undeveloped properties.

Revenue. During fiscal 2005, oil and natural gas revenue from continuing operations increased 144% to $90.9 million, as compared to $37.2 million in fiscal 2004. The increase was the result of (i) an average onshore gas price received in fiscal 2005 of $5.79 per Mcf compared to $5.27 per Mcf in 2004, (ii) an increase in average onshore oil price received in fiscal 2005 of $47.05 per Bbl compared to $33.09 per Bbl in 2004, (iii) an increase in offshore oil price received of $33.37 per Bbl in fiscal 2005 compared to $22.11 in 2003, and (iv) a 91% increase in average daily production over the prior year.

Cash payments required on our hedging activities impacted revenues in 2005 and 2004. The cost of settling our hedging activities was $960,000 in fiscal 2005 and $859,000 in fiscal 2004.

Production volumes, average prices received and cost per equivalent Mcf for the years ended June 30, 2005 and 2004 are as follows:

	Years Ended June 30,			
	2005		2004	
	Onshore	Offshore	Onshore	Offshore
Production:				
Oil (MBbl)	899	156	552	180
Gas (MMcf)	7,501	-	2,841	-
Production – Discontinued Operations:				
Oil (MBbl)	2	-	16	-
Gas (MMcf)	174	-	269	-
Average Price – Continuing Operations:				
Oil (per barrel)	$ 47.05	$ 33.37	$ 33.09	$ 22.11
Gas (per Mcf)	$ 5.79	$ -	$ 5.27	$ -
Costs per Mcfe				
Hedge effect	$ (.07)	$ -	$ (.14)	$ -
Lease operating expense	$ .92	$ 4.00	$ .70	$ 2.98
Production taxes	$ .46	$ .21	$ .31	$ .04
Transportation costs	$ .04	$ -	$ .04	$ -
Depletion expense	$ 1.57	$ .77	$ 1.46	$ .65

Lease Operating Expense. Lease operating expenses for the year ended June 30, 2005 were $15.6 million compared to $7.5 million for the same periods a year earlier. Lease operating expense from continuing operations for onshore properties for the year ended June 30, 2005 was $.92 per Mcfe as compared to $.70 per Mcfe for the same period a year earlier. Lease operating expense from continuing operations for offshore properties was $4.00 per Mcfe for the year ended June 30, 2005 and $3.76 per Mcfe for the same period a year earlier. This increase in lease operating costs from continuing operations per Mcfe can be primarily attributed to the completion of the Manti acquisition in January 2005 and the Alpine acquisition in June 2004. The assets acquired in these two transactions have higher production costs than the asset base previously owned.

Depreciation and Depletion Expense. Depreciation and depletion expense increased 134% to $23.2 million in fiscal 2005, as compared to $9.9 million in fiscal 2004. Depreciation and depletion expenses for our onshore properties increased to $1.57 per Mcfe during fiscal 2005 from $1.46 per Mcfe in fiscal 2004. Depletion rates have increased based on the higher amounts paid to acquire reserves in the ground and the increase in drilling costs. In addition, we incurred higher depletion rates caused by lower proved developed producing reserves in our South Angleton and Padgett fields. The reduction in the South Angleton field was from unsuccessful drilling results, while the reduction in reserves in the Padgett field was from a seismic survey that indicated a smaller reservoir than originally anticipated. Our depletion rate in our Newton field also increased as a result of drilling and completing inefficiencies and under-performing wells. Our last two wells which were completed in late June were on budget and had predictable initial results. We anticipate overall depletion rates for us and our competitors to increase under the current pricing environment.

Dry Hole Costs. We incurred dry hole costs of approximately $2.8 million for the year ended June 30, 2005 compared to $2.1 million for the same period a year ago. A significant portion of these costs relate to our Trail Blazer prospect in Laramie County, Wyoming. Included in the dry holes were four non-Niobrara formation dry holes in Washington County, Colorado.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended June 30, 2005 were $6.2 million compared to $2.4 million for the prior year. Current year activities include newly acquired seismic information in Washington County, Colorado, Polk County, Texas and Laramie County, Wyoming. Currently, we are obtaining seismic information on 22.75 square miles in Washington County, Colorado on our North Tongue Prospect and will be expanding our South Tongue Prospect shoot to include a 46 square mile shoot during fiscal 2006.

Drilling and Trucking Operations. In March 2004, we acquired a 50% interest in both the Big Dog Drilling Company and Shark Trucking Company to enable us to have access to drilling rigs and rig transportation facilities on a priority basis. On March 31, 2005, we purchased the remaining interest in Big Dog Drilling Co., LLC ("Big Dog") for our interest in Shark Trucking, LLC ("Shark"), one of Big Dog's rigs and related equipment and 100,000 shares of our stock valued at $1.4 million, based on the average stock price five days before and after the announcement of the transaction. On April 15, 2005, we conveyed our interest in Big Dog to DHS Drilling Company in exchange for 4,500,000 shares of DHS Drilling Company's restricted stock, or 90% of its issued and outstanding shares. The remaining 10% was then owned by two officers of DHS who will earn their interest over five years of employment. Effective May 1, 2005, DHS sold 45% of its restricted stock to Chesapeake Energy, Inc. for $15.0 million. Delta currently owns 49.5% of DHS and controls both the board of directors, access to all drilling rigs for company use and operations. We had drilling and trucking income of $4.8 million offset by drilling and trucking expenses of $4.7 million during the year ended June 30, 2005.

Professional Fees. Professional fees include corporate legal costs, accounting fees, shareholder relations consultants and legal fees for representation in negotiations and discussions with various state and federal governmental agencies relating to our undeveloped offshore California leases. Our professional fees increased 71% to $2.0 million for fiscal 2005, as compared to $1.2 million for fiscal 2004. The increase in professional fees can be attributed largely to compliance with the Sarbanes-Oxley Act.

General and Administrative Expense. General and administrative expense increased 116% to $14.9 million in fiscal 2005, as compared to $6.9 million in fiscal 2004. The increase in general and administrative expenses is primarily attributed to (i) the 95% increase in technical and administrative staff and related personnel costs, (ii) the expansion of our office facility and (iii) $824,000 of vested restricted stock and option awards granted to officers, directors and management.

Minority Interest. Minority interest represents the minority investors' percentage of their share of income or losses from Big Dog, Shark or DHS in which they hold an interest.

Interest and Financing Costs. Interest and financing costs increased 352% to $8.0 million in fiscal 2005, as compared to $1.8 million in fiscal 2004. The increase is primarily related to the $150.0 million senior note offering completed in March 2005 and the increase in the average amount outstanding under our credit facility primarily as a result of the Manti acquisition completed in January 2005 and our increased investment in the Columbia River prospect in Washington completed in April 2005.

Fiscal 2004 Compared to Fiscal 2003

Net income. Net income increased $3.8 million to $5.1 million or $.17 per diluted common share for fiscal 2004, an increase of 302% as compared to $1.3 million or $.05 per diluted common share for fiscal 2003. This increase was primarily due to a 40% increase in production from fiscal 2003 relating to acquisitions completed during fiscal 2004 and 2003, the development of undeveloped properties associated with these acquisitions and an increase in average oil and natural gas prices received by Delta.

Revenue. During fiscal 2004, oil and natural gas revenue from continuing operations increased 65% to $37.2 million, as compared to $22.6 million in fiscal 2003. The increase was the result of (i) an average for onshore gas price received in fiscal 2004 of $5.27 per Mcf compared to $4.71 per Mcf in 2003, (ii) an increase in average onshore oil price received in fiscal 2004 of $33.09 per Bbl compared to $28.82 per Bbl in 2003, (iii) a slight increase in offshore oil price received of $22.11 per Bbl in fiscal 2004 compared to $20.21 in 2003 and (iv) a 40% increase in average daily production during the fiscal year previously discussed above.

Cash payments required on our hedging activities impacted revenues in 2004 and 2003. The cost of settling our hedging activities was $859,000 in fiscal 2004 and $1.9 million in fiscal 2003.

Production volumes, average prices received and cost per equivalent Mcf for the years ended June 30, 2004 and 2003 were as follows:

	Years Ended June 30,			
	2004		2003 (1)	
	Onshore	Offshore	Onshore	Offshore
Production:				
Oil (MBbl)	552	180	217	227
Gas (MMcf)	2,841	-	2,492	-
Production – Discontinued Operations:				
Oil (MBbl)	16	-	35	-
Gas (MMcf)	269	-	446	-
Average Price – Continuing Operations:				
Oil (per barrel)	$ 33.09	$ 22.11	$ 28.82	$ 20.21
Gas (per Mcf)	$ 5.27	$ -	$ 4.71	$ -
Costs per Mcfe				
Hedge effect	$ (.14)	$ -	$ (.49)	$ -
Lease operating expense	$ .70	$ 2.98	$ .99	$ 2.35
Production taxes	$ .31	$ .04	$ .30	$ .05
Transportation costs	$ .04	$ -	$ .06	$ -
Depletion expense	$ 1.46	$ .65	$ 1.02	$ .79

(1) 2003 information has changed to comply with FAS 144 "Accounting for the Impairment or Disposal of Long-Lived Assets."

Lease Operating Expense. Lease operating expense increased 8% to $7.5 million for fiscal 2004, as compared to $7.0 million for 2003, however, onshore lease operating costs per Mcfe decreased from $.99 per Mcfe in fiscal 2003 to $.70 per Mcfe in fiscal 2004. This decrease in production cost per Mcfe can primarily be attributed to our Padgett Field acquisition completed during fiscal 2003. The Padgett Field added an additional 1.2 Bcfe to current year production with an associated cost of $.22 per Mcfe.

Depreciation and Depletion Expense. Depreciation and depletion expense increased 96% to $9.9 million in fiscal 2004, as compared to $5 million in fiscal 2003. Depreciation and depletion expenses per Mcfe for our onshore properties increased to $1.46 per Mcfe during fiscal 2004 from $1.02 per Mcfe in fiscal 2003. This increase can be attributed to the acquisition of our Christensen Field in Washington County which had a depreciation and depletion expense of $2.40 per Mcfe and the acquisition of our Eland and Stadium fields which had depreciation and depletion expense of $2.74 per Mcfe.

Dry Hole Costs. We incurred dry hole costs of $2.1 million on five exploratory wells in fiscal 2004 and $537,000 on three exploratory wells in fiscal 2003.

Exploration Expenses. Exploration expenses consist of geological and geophysical costs and lease rentals. Our exploration costs for fiscal 2004 of $2.4 million included an extensive 78 square mile seismic shoot in Washington County, Colorado on our South Tongue Prospect. Currently, we are obtaining seismic information on 22.75 square miles in Washington County, Colorado on our North Tongue Prospect and will be expanding our South Tongue Prospect shoot to include a 75 square mile shoot during fiscal 2005.

Drilling and Trucking Operations. In March 2004, we acquired a 50% interest in both the Big Dog Drilling Co., LLC and Shark Trucking Co., LLC. We began drilling our first well with a Big Dog rig in August 2004 and will primarily drill on our acreage. The cost associated with these two entities represents start up costs incurred through year end.

Professional Fees. Professional fees include corporate legal costs, accounting fees, shareholder relations consultants and legal fees for representation in negotiations and discussions with various state and federal governmental agencies relating to our undeveloped offshore California leases. Our professional fees increased 43% to $1.2 million for fiscal 2004, as compared to $842,000 for fiscal 2003. The increase in professional fees can attributed largely to the compliance with the Sarbanes-Oxley Act.

General and Administrative Expense. General and administrative expense increased 60% to $6.9 million in fiscal 2004, as compared to $4.3 million in fiscal 2003. The increase in general and administrative expenses is primarily attributed to (i) the increase in technical and administrative staff and related personnel costs, (ii) the expansion of our office facility and (iii) additional bonuses earned by officers and management.

Interest and Financing Costs. Interest and financing costs remained consistent with fiscal 2003. We expensed $1.8 million for both fiscal 2004 and 2003. The decrease in interest rates during fiscal 2004 was offset by the increase in long-term debt obligations during the year.

Discontinued Operations. Included in discontinued operations are (i) income (loss) from operations of properties sold and (ii) gain (loss) on sale of oil and gas properties. We are required to re-class related revenue and expenses relating to sales of our oil and gas properties for all periods presented. During fiscal 2004, we sold our Pennsylvania properties which resulted in a gain on sale of $1.9 million. During fiscal 2003, we sold some non-strategic oil and gas properties which resulted in a gain of $277,000.

Liquidity and Capital Resources

Liquidity is a measure of a company's ability to access cash. We have historically addressed our long-term liquidity requirements through the issuance of debt and equity securities when market conditions permitted, and through cash provided by operating activities and sale of oil and gas properties. On March 15, 2005, we issued 7% senior notes, unsecured, for an aggregate amount of $150.0 million. At the same time, we also increased our credit facility to $200.0 million with an available borrowing base of $75.0 million, $8.5 million of which is not drawn at June 30, 2005. Subsequent to year end on September 2, 2005 we sold our non-core Deerlick Field located in Tuscaloosa, Alabama for $30.0 million, subject to adjustments.

The prices we receive for future oil and natural gas production and the level of production have a significant impact on operating cash flows. We are unable to predict with any degree of certainty the prices we will receive for our future oil and gas production.

We continue to examine alternative sources of long-term capital, including bank borrowings, the issuance of debt instruments, the sale of common stock, the sales of non-strategic assets, and joint venture financing. Availability of these sources of capital and, therefore, our ability to execute our operating strategy will depend upon a number of factors, some of which are beyond our control.

We believe that borrowings under the Revolving Credit Facility, projected operating cash flows and cash on hand will be sufficient to meet the requirements of our business; however, future cash flows are subject to a number of variables, including the level of production and oil and natural gas prices. We cannot give assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or that increased capital expenditures will not be undertaken. Actual levels of capital expenditures may vary significantly due to a variety of factors, including but not limited to, drilling results, product pricing and future acquisition and divestitures of properties.

Company Acquisitions and Growth

We continue to evaluate potential acquisitions and property development opportunities. During fiscal 2005, we completed the following transactions:

On July 1, 2004, we acquired certain interests in California's Sacramento Basin and a 7.5% reversionary working interest in the South Tongue interests in Washington County, Colorado from Edward Mike Davis, LLC, which was then a greater than 5% shareholder ("Davis"), for 760,000 shares of our common stock valued at $10.4 million using the five-day closing price before and after the terms of the agreement were agreed and closed, which was $13.63.

On September 15, 2004, we acquired seven wells in Karnes County, Texas from an unrelated entity and an unrelated individual for $5.0 million in cash.

On November 4, 2004, we entered into an agreement with Davis to acquire the balance of his back-in working interest and his overriding royalty interest in all of his ownership to the base of the Niobrara formation in the South Tongue interests in Washington County, Colorado. This agreement eliminated all future drilling commitments in Washington County. This included approximately 260,000 acres of leasehold. In addition, we acquired a 100% working interest with a 70% net revenue interest in the Magers 1-9 well which is a newly drilled well in Colusa County, California. Total consideration was 650,000 shares of our common stock valued at approximately $9.4 million. Also on November 4, 2004, we entered into an agreement with Davis to acquire and possibly develop certain areas in Elbert County, Colorado. The initial cost of this transaction was 25,000 shares of our common stock valued at approximately $363,000.

On December 15, 2004, we entered into a purchase and sale agreement to acquire substantially all of the oil and gas assets owned by several entities related to Manti Resources, Inc., which was an unaffiliated, privately held Texas corporation ("Manti"). The adjusted purchase price was $59.7 million. The entire amount of the purchase price was paid in cash at the closing of the transaction, which occurred on January 21, 2005. The purchase price for the Manti properties was determined through arms-length negotiations. The purchase price was paid with increased borrowings from our existing bank credit facility. Substantially all of the assets that we acquired from Manti have been pledged as collateral under our credit facility.

On January 4, 2005 we acquired additional interests in the South Tongue area of Washington County and also entered into an exploration agreement with Davis in Los Angeles and Orange Counties, California. We paid Davis $400,000 in cash and 135,836 shares of our common stock valued at $2.0 million, of which $1.1 million was attributable to South Tongue.

On March 31, 2005, we purchased the remaining interest in Big Dog in exchange for our interest in Shark, one of Big Dog's rigs, certain related equipment and 100,000 shares of our restricted stock valued at $1.4 million. On April 15, 2005, we conveyed our interest in Big Dog to DHS in exchange for 4,500,000 shares of DHS restricted stock, or 90% of its issued and outstanding shares. On May 16, 2005, DHS sold 45% of its restricted stock to Chesapeake Energy, Inc. for $15 million. We currently own 49.5% of DHS. We control the board of directors and operations and have a right to use their rigs. As such, the operations of DHS have been consolidated into ours.

On May 4, 2005, we purchased from Savant 14.25% back-in working interest in approximately 427,000 acres in the Columbia River Basin for $18.2 million in cash. The acreage is in close proximity to many of our existing leasehold interests in the basin and includes a lease on which another operator is currently drilling. The interest acquired is a non-cost bearing interest with a back-in after project payout. We can, however, at any time and at our discretion, convert the interest to a cost bearing working interest by paying our proportionate share of the costs incurred in the project.

On September 7, 2005 we entered into an agreement to purchase an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington, and to purchase an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant for an aggregate purchase price of $85.0 million, on or before September 30, 2005. James Wallace, a director of Delta, owns approximately a 1.7% interest in Savant, and also serves as a director of Savant. The majority of the acquired acreage in the Columbia River Basin consolidates our current leasehold position, whereby subsequent to the acquisition we will own a 100% working interest in approximately 310,000 net acres. This acquisition also includes a small portion of acreage that is subject to an agreement with EnCana Oil & Gas (USA) Inc., whereby we will have to a working interest at project payout. In the Piceance Basin, we are acquiring Savant's interest in an entity that owns a 25% interest in approximately 6,314 gross acres that is currently being developed. The financing alternatives for this acquisition are still being investigated.

Historical Cashflow

Our cashflow from operating activities increased 366% to $44.9 million for the year ended June 30, 2005 compared to $9.6 million for the same period a year earlier, primarily as a result of a 161% increase in revenue and a 134% increase in non cash depletion expense. Our net cash used in investing activities increased by 24% to $183.9 million for the year ended June 30, 2005 compared to $148.4 million for the same period a year earlier. The increase in cash used for investing activity can be attributed to the expansion of our drilling programs in both the Rocky Mountain and Gulf Coast regions along with additional drilling rig acquisitions. Cashflow from financing was $139.2 million for the year ended June 30, 2005 which was consistent with $138.6 for the same period the prior year. During fiscal 2005, we financed our operations primarily with debt. On March 15, 2005, we issued 7% senior unsecured notes for an aggregate amount of $150.0 million. During fiscal 2004, we financed our operations with the issuance of $98.0 million in equity and an increase in our bank credit facility.

Capital and Exploration Expenditures and Financing

Our capital and exploration expenditures and sources of financing for the years ended June 30, 2005, 2004 and 2003 are as follows:

	Year Ended June 30,		
	2005	2004 (In thousands)	2003
CAPITAL AND EXPLORATION EXPENDITURES:			
Acquisitions:			
Manti	$ 59,700	$ -	$ -
Columbia River Basin	18,255	-	-Washington,
County South and North Tongue	10,571	30,406	-
Sacramento Basin	10,400	-	-
Karnes County, Texas	5,000	-	-
Alpine Resources	-	120,655	-
Padgett	-	-	9,631
Other	2,718	-	-
Development costs	102,216	37,969	8,468
Drilling and trucking companies	32,690	3,965	-
Exploration costs	6,155	2,406	140
	$247,705	$ 195,401	$ 18,239
FINANCING SOURCES:			
Cash flow provided by operating activities	$ 44,862	$ 9,623	$ 7,999
Stock issued for cash upon exercised options	132	3,563	975
Issuance of common stock for cash	-	97,902	-
Net long-term borrowings	139,051	37,157	6,921
Proceeds from sale of oil and gas properties	18,721	10,787	850
Other	14,863	(721)	139
	$217,629	$ 158,311	$ 16,884

We anticipate our capital and exploration expenditures to range between $50.0 and $65.0 million for the six months ending December 31, 2005. The timing of most of our capital expenditures is discretionary.

Sale of Oil and Gas Properties - Discontinued Operations

On August 19, 2004, we completed the sale of our interests in five fields in Louisiana and South Texas previously acquired in the Alpine acquisition, which closed on June 29, 2004, to Whiting Petroleum Corporation for $18.7 million, net of commission. We paid $8.8 million on our credit facility balance from the sale of these properties. No gain or loss was recognized on this transaction.

On September 9, 2005, we completed the sale of our interest in the Deerlick Field located in Tuscaloosa, Alabama, for cash consideration of $30.0 million and an effective date of July 1, 2005. We expect to record a gain on sale of oil and gas properties of approximately $18.9 million. Revenues from these oil and gas properties were approximately $4.9 million, $3.3 million and $3.0 million for the years ended June 30, 2005, 2004 and 2003, respectively.

Contractual and Long-Term Debt Obligations

	Payments Due by Period				
Contractual Obligations at June 30, 2005	Less than 1 year	2-3 Years	4-5 Years	After 5 Years	Total
			(In thousands)		
7% Senior unsecured notes	$ -	$ -	$ -	$150,000	$ 150,000
Interest on 7% Senior unsecured notes	10,500	21,000	21,000	48,511	101,011
Credit facility	-	-	66,500	-	66,500
Abandonment retirement obligation	716	123	935	6,515	8,289
Derivative liability	7,241	3,620	-	-	10,861
Operating leases	1,998	1,643	1,542	3,564	8,747
Other debt obligations	143	221	8	-	372
Total contractual cash obligations	$ 20,598	$ 26,607	$ 89,985	$208,590	$ 345,780

7% Senior Unsecured Notes, due 2015

On March 15, 2005, we issued 7% senior unsecured notes for an aggregate amount of $150.0 million which pay interest semiannually on April 1 and October 1 and mature in 2015. The net proceeds were used to refinance debt outstanding under our credit facility which included the amount required to acquire the Manti properties. The notes were issued at 99.50% of par and the associated discount is being amortized to interest expense over the term of the notes. The indenture governing the notes contains various restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, make certain investments, sell assets, consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries. These covenants may limit management's discretion in operating our business.

Credit Facility

On June 30, 2005, we amended our credit facility with Bank One, N.A., Bank of Oklahoma N.A., U.S. Bank National Association and Hibernia National Bank (the "Banks"). At June 30, 2005, the $200.0 million credit facility had an available borrowing base of approximately $75.0 million and $66.5 million outstanding. The temporary reduction in available borrowing base was established until certain drilling results were attained. We anticipate our available borrowing base to increase with future drilling success. The facility has variable interest rates based upon the ratio of outstanding debt to the borrowing base. Rates vary between prime + .25% and 1.00% for base rate loans and between Libor + 1.5% and 2.25% for Eurodollar loans. The loan was collateralized by substantially all of our oil and gas properties. Currently, we are required to meet certain financial covenants which include a current ratio of 1 to 1, net of derivative instruments and a consolidated debt to EBITDAX (Earnings before interest, taxes, depreciation, amortization and exploration) of less than 3.5 to 1. The financial covenants only include subsidiaries which we own 100%. At June 30, 2005, we were not in compliance with our quarterly debt covenants and restrictions, but have obtained a waiver from our banks for the quarter ended June 30, 2005.

Subsequent determinations of the borrowing base will be made by the lending banks at least semi-annually on April 1 and October 1 of each year or as special re-determinations. If, as a result of any reduction in the amount of our borrowing base, the total amount of the outstanding debt were to exceed the amount of the borrowing base in effect, then, within 30 days after we are notified of the borrowing base deficiency, we would be required (1) to make a mandatory payment of principal to reduce our outstanding indebtedness so that it would not exceed our borrowing base and (2) to eliminate the deficiency by making three equal monthly principal payments, (3) within 90 days to provide additional collateral for consideration to eliminate the deficiency or (4) to eliminate the deficiency through a combination of (1) through (3). If for any reason we were unable to pay the full amount of the mandatory prepayment within the requisite 30-day period, we would be in default of our obligations under our credit facility.

The credit facility includes terms and covenants that place limitations on certain types of activities, including restrictions or requirements with respect to additional debt, liens, asset sales, hedging activities, investments, dividends, mergers and acquisitions, and includes financial covenants.

Under certain conditions amounts outstanding under the credit facility may be accelerated. Bankruptcy and insolvency events with respect to us or certain of our subsidiaries will result in an automatic acceleration of the indebtedness under the credit facility. Subject to notice and cure periods in certain cases, other events of default under the credit facility will result in acceleration of the indebtedness at the option of the lending banks. Such other events of default include non-payment, breach of warranty, non-performance of obligations under the credit facility (including financial covenants), default on other indebtedness, certain pension plan events, certain adverse judgments, change of control, and a failure of the liens securing the credit facility.

This facility is secured by a first and prior lien to the lending banks on most of our oil and gas properties, certain related equipment, oil and gas inventory, and certain bank accounts and proceeds.

Other Contractual Obligations

Our abandonment retirement obligation arises from the plugging and abandonment liabilities for our oil and gas wells. The majority of this obligation will not occur over the next five years.

Our corporate office in Denver, Colorado is under an operating lease which will expire in fiscal 2015. Our average yearly payments approximate $772,000 over the life of the lease. We have additional operating lease commitments which represent office equipment leases and short term debt obligations primarily relating to field vehicles and equipment.

Derivative instruments represent the net estimated unrealized losses for our oil and gas hedges at June 30, 2005. The ultimate settlement amounts of these hedges are unknown because they are subject to continuing market risk.

The following table summarizes our derivative contracts, which were all designated as hedges at June 30, 2005:

Commodity	Volume	Price Floor / Price Ceiling	Term	Index	Fair Value at June 30, 2005 (In thousands)
Crude oil	6,000 Bbls / month	$ 35.00 / $ 49.75	Apr '05 - Dec '05	NYMEX-WTI	$ 335
Crude oil	40,000 Bbls / month	$ 40.00 / $ 50.34	July '05 - June '06	NYMEX-WTI	4,629
Crude oil	10,000 Bbls / month	$ 45.00 / $ 56.90	July '05 - June '06	NYMEX-WTI	599
Crude oil	25,000 Bbls / month	$ 35.00 / $ 61.80	July '06 - June '07	NYMEX-WTI	1,681
Natural gas	3,000 MMBtu / day	$ 5.00 / $ 7.85	Apr '05 - Oct '05	NYMEX-H HUB	40
Natural gas	10,000 MMBtu / day	$ 5.00 / $ 9.60	July '05 - June '06	NYMEX-H HUB	995
Natural gas	3,000 MMBtu / day	$ 6.00 / $ 9.35	July '05 - June '06	NYMEX-H HUB	255
Natural gas	13,000 MMBtu / day	$ 5.00 / $ 10.20	July '06 - June '07	NYMEX-H HUB	1,466
					$ 10,000

The fair value of our derivative instruments obligation was $10.0 million at June 30, 2005 and $23.3 million on September 12, 2005.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations were based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our consolidated financial statements. In response to SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas reserves, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements.

Successful Efforts Method of Accounting

We account for our natural gas and crude oil exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine that proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver gas and oil in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of gas and oil leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in hopes of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

Estimates of gas and oil reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of gas and oil that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable gas and oil reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future gas and oil prices, future operating costs, severance taxes, development costs and workover gas costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of gas and oil attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our gas and oil properties and/or the rate of depletion of the gas and oil properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Impairment of Gas and Oil Properties

We review our oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of our developed proved properties and compare such future cash flows to the carrying amount of the proved properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and gas properties to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected.

Given the complexities associated with gas and oil reserve estimates and the history of price volatility in the gas and oil markets, events may arise that would require us to record an impairment of the recorded book values associated with gas and oil properties. We did not record an impairment during the years ended June 30, 2005, 2004 or 2003.

Commodity Derivative Instruments and Hedging Activities

We periodically enter into commodity derivative contracts and fixed-price physical contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize future contracts, swaps or options, which are generally placed with major financial institutions or with counterparties of high credit quality that we believe are minimal credit risks. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive.

On January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Under SFAS No. 133 all derivative instruments are recorded on the balance sheet at fair value. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective. At June 30, 2005, $6.0 million is in accumulated other comprehensive income and represents the potential reduction in future net revenue and cashflow. For qualifying fair value hedges, the gain or loss on the derivative is offset by related results of the hedged item in the income statement. Gains and losses on hedging instruments included in accumulated other comprehensive income (loss) are reclassified to oil and natural gas sales revenue in the period that the related production is delivered. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. While such derivative contracts do not qualify for hedge accounting, management believes these contracts can be utilized as an effective component of commodity price risk management (CPRM) activities.

Recently Issued Accounting Standards and Pronouncements

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3* ("Statement 154"). SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The implementation of FAS 154 is not expected to have a material impact on our condensed consolidated results of operations, financial position or cash flows.

In December 2004, the FASB issued its final standard on accounting for employee stock options, FAS No. 123 (Revised 2004), "Share-Based Payment" ("FAS123(R)"). FAS 123(R) replaces FAS No. 123, "Accounting for Stock-

Based Compensation" ("FAS 123"), and supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." FAS 123(R) requires companies to measure compensation costs for all share-based payments, including grants of employee stock options, based on the fair value of the awards on the grant date and to recognize such expense over the period during which an employee is required to provide services in exchange for the award. The pro forma disclosures previously permitted under FAS 123 will no longer be an alternative to financial statement recognition. FAS 123(R) is effective for all awards granted, modified, repurchased or cancelled after, and to unvested portions of previously issued and outstanding awards vesting after, interim or annual periods, beginning after June 15, 2005, which for us will be the first quarter of fiscal 2006. We are currently evaluating the effect of adopting FAS 123(R) on our financial position and results of operations, and we have not yet determined whether the adoption of FAS 123(R) will result in expenses in amounts that are similar to the current pro forma disclosures under FAS 123.

In February 2005, the staff of the Securities and Exchange Commission sent a letter to oil and gas registrants regarding situations that require additional financial statement disclosures, pending final resolution of accounting treatment. The following are items related to registrants using the successful efforts method of accounting:

- Companies may enter concurrent commodity buy/sale arrangements, or transactions in contemplation of other transactions, often to assure that the commodity is available at a specific location. Pending resolution of accounting questions with the Emerging Issues Task Force, the Commission staff has requested additional disclosures for any such material arrangements, including separate disclosure on the face of the income statement of any related proceeds and costs reported on a gross basis. These disclosures are not applicable to us since we have not entered any significant transactions of this nature.

- Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. In April 2005, the FASB issued FASB Staff Position 19-1, Accounting for Suspended Well Costs. FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, however, early application is permitted. Pending adoption of FSP 19-1, the Commission staff has requested additional disclosures be included in registrants' financial statements regarding their accounting policy for capitalization of exploratory drilling costs, as well as disclosure of capitalized exploratory drilling cost amounts included in the financial statements. We generally pursue development of proved reserves as opposed to exploration activities, and our drill well costs are generally transferred to producing properties within one month of the well completion date.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the potential loss arising from adverse changes in market rates and prices, such as foreign currency exchange and interest rates and commodity prices. We do not use financial instruments to any degree to manage foreign currency exchange and interest rate risks and do not hold or issue financial instruments to any degree for trading purposes. All of our revenue and related receivables are payable in U.S. dollars.

Market Rate and Price Risk

We began to hedge a portion of our oil and gas production using swap and collar agreements. The purpose of these hedge agreements is to provide a measure of stability to our cash flow in an environment of volatile oil and gas prices and to manage the exposure to commodity price risk.

The current derivative contracts cover approximately 40% of our current daily production. Assuming production and, the percent of oil and gas sold remained unchanged from the year ended June 30, 2005, a hypothetical 10% decline in the average market price the Company realized during the year ended June 30, 2005 on unhedged production would reduce the Company's oil and natural gas revenues by approximately $9.1 million on an annual basis.

Interest Rate Risk

We were subject to interest rate risk on $66.5 million of variable rate debt obligations at June 30, 2005. The annual effect of a ten percent change in interest rates would be approximately $333,000. The interest rate on these variable rate debt obligations approximates current market rates as of June 30, 2005.

FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors
Delta Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Delta Petroleum Corporation and subsidiaries as of June 30, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss) and cash flows for the years ended June 30, 2005, 2004 and 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Delta Petroleum Corporation and subsidiaries as of June 30, 2005 and 2004, and the results of their operations and their cash flows for each of the years ended June 30, 2005, 2004 and 2003, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of June 30, 2005, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of the Sponsoring Organizations of the Treadway Commission, and our report dated September 15, 2005 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

As discussed in footnote 2 to the consolidated financial statements, Delta Petroleum Corporation adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* as of July 1, 2002.

KPMG
Denver, Colorado
September 15, 2005

Report of Independent Registered Public Accounting Firm

The Board of Directors
Delta Petroleum Corporation:

We have audited management's assessment, included in Item 9A, *Management's Report on Internal Control over Financial Reporting,* that Delta Petroleum Corporation and subsidiaries (Delta or the Company) maintained effective internal control over financial reporting as of June 30, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Delta's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Delta maintained effective internal control over financial reporting as of June 30, 2005 is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, Delta maintained, in all material respects, effective internal control over financial reporting as of June 30, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Delta and subsidiaries as of June 30, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the years ended June 30, 2005, 2004 and 2003 and our report dated September 15, 2005 expressed an unqualified opinion on those consolidated financial statements.

As discussed in footnote 2 to the consolidated financial statements, Delta Petroleum Corporation adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, as of July 1, 2002.

KPMG
Denver, Colorado
September 15, 2005

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	June 30, 2005	June 30, 2004
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,241	$ 2,078
Marketable securities available for sale	1,764	912
Trade accounts receivable, net of allowance for doubtful accounts, of $100 and $50, respectively	10,512	9,092
Prepaid assets	2,980	1,136
Inventory	5,062	1,350
Deferred tax asset	2,676	-
Derivative instruments	378	-
Other current assets	1,421	385
Total current assets	27,034	14,953
Property and equipment:		
Oil and gas properties, successful efforts method of accounting:		
Unproved	101,935	49,747
Proved	365,306	223,145
Drilling equipment, including deposits on equipment of $7.5 million	40,031	3,965
Other	10,412	1,147
Total property and equipment	517,684	278,004
Less accumulated depreciation and depletion	(44,134)	(21,665)
Net property and equipment	473,550	256,339
Long-term assets:		
Investment in LNG project	1,022	1,022
Deferred financing costs	5,825	131
Deferred tax assets	4,887	-
Derivative instruments	469	-
Other long-term assets	196	259
Total long-term assets	12,399	1,412
Total assets	$ 512,983	$ 272,704
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 3,477	$ 109
Accounts payable	38,151	12,326
Other accrued liabilities	5,281	1,855
Derivative instruments	7,241	-
Total current liabilities	54,150	14,290
Long-term liabilities:		
7% Senior notes, unsecured	149,272	-
Credit facility	66,500	69,375
Asset retirement obligation	2,975	2,542
Derivative instruments	3,620	-
Other debt, net	229	255
Total long-term liabilities	222,596	72,172
Minority interest	14,614	245
Commitments		
Stockholders' equity:		
Preferred stock, $.10 par value: authorized 3,000,000 shares, none issued	-	-
Common stock, $.01 par value; authorized 300,000,000 shares, issued 42,017 000 shares at June 30, 2005 and 38,447,000 shares at June 30, 2004	420	384
Additional paid-in capital	235,300	207,811
Unearned compensation	(1,382)	-
Accumulated other comprehensive (loss) income	(5,225)	342
Accumulated deficit	(7,490)	(22,540)
Total stockholders' equity	221,623	185,997
Total liabilities and stockholders' equity	$ 512,983	$ 272,704

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended June 30,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Revenue:			
Oil and gas sales	$ 90,871	$ 37,226	$ 22,576
Drilling and trucking	4,796	-	-
Realized loss on derivative instruments, net	(960)	(859)	(1,858)
Total revenue	94,707	36,367	20,718
Operating expenses:			
Lease operating expense	15,566	7,530	6,966
Transportation expense	575	259	230
Production taxes	6,128	1,978	1,214
Depreciation and depletion	23,207	9,914	4,999
Exploration expense	6,155	2,406	140
Dry hole costs	2,771	2,132	537
Drilling and trucking operations	4,666	232	-
Professional fees	2,010	1,174	842
General and administrative	14,920	6,875	4,295
Total operating expenses	75,998	32,500	19,223
Operating income	18,709	3,867	1,495
Other income and (expense):			
Other income (expense)	(492)	122	31
Minority interest	1,017	70	-
Interest and financing costs	(7,958)	(1,762)	(1,767)
Total other expense	(7,433)	(1,570)	(1,736)
Income (loss) from continuing operations	11,276	2,297	(241)
Income tax expense (benefit):			
Current	-	-	-
Deferred	(3,325)	-	-
Total income tax (benefit)	(3,325)	-	-
Net earnings from continuing operations	14,601	2,297	(241)
Income from discontinued operations of properties sold, net of tax	449	872	1,241
Gain on sale of discontinued operations, net of tax	-	1,887	277
Cumulative effect of change in accounting principle, net of tax	-	-	(20)
Net income	$ 15,050	$ 5,056	$ 1,257
Basic income (loss) per common share:			
Net income (loss) from continuing operations	$ .36	$ .09	$ (.01)
Discontinued operations, net of tax	.01	.10	.06
Cumulative effect of change in accounting principle, net of tax	-	-	*
Basic net income per share	$ .37	$ .19	$ .05
Diluted income per common share:			
Net earnings (loss) from continuing operations	$ .36	$ .08	$ (.01)
Discontinued operations, net of tax	.01	.09	.06
Cumulative effect of change in accounting principle	-	-	*
Diluted net income per share	$ .36	$ .17	$ .05

* Less than $.01 per common share

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
Consolidated Statement of Changes in Stockholders' Equity and Comprehensive Income (Loss)

	Common stock Shares	Common stock Amount	Additional paid-in capital	Accumulated other comprehensive income/(loss)	Comprehensive income (loss)	Unearned Compensation	Accumulated deficit	Total
	(In thousands, except per share amounts)							
Balance, July 1, 2002	22,618	$ 226	$76,514	$ (85)			$ (28,853)	$44,916
Comprehensive income:								
Net income	-	-	-	-	$ 1,257		1,257	1,257
Other comprehensive income, net of tax								
Change in fair value of derivative hedging instruments	-	-	-	(468)	(468)		-	(468)
Unrealized gain on marketable securities, net	-	-	-	177	177		-	177
Comprehensive income	-	-	-	-	$ 966			
Stock options granted as compensation	-	-	124	-				124
Put option on Delta Stock	-	-	(2,886)					-
Shares issued for oil and gas properties	200	2	920	-			-	922
Shares issued for cash upon exercise of options	468	5	970	-			-	975
Balance, June 30, 2003	23,286	233	75,642	(376)			(27,596)	47,903
Comprehensive income:								
Net income	-	-	-	-	$ 5,056		5,056	5,056
Other comprehensive gain, net of tax								
Change in fair value of derivative hedging instruments	-	-	-	468	468		-	468
Unrealized gain on marketable securities, net	-	-	-	250	250		-	250
Comprehensive income	-	-	-	-	$ 5,774			
Stock options granted as compensation			329	-			-	329
Shares issued for cash, net	10,000	100	97,802	-			-	97,902
Shares issued for oil and gas properties	3,728	37	30,489	-			-	30,526
Shares issued for cash upon exercise of options	1,433	14	3,549	-			-	3,563
Balance, June 30, 2004	38,447	384	207,811	342			(22,540)	185,997
Comprehensive income:								
Net income	-	-	-	-	$ 15,050		15,050	15,050
Other comprehensive gain, net of tax								
Change in fair value of derivative hedging instruments, net of tax benefit of $3,722	-	-	-	(5,961)	(5,961)		-	(5,961)
Unrealized gain on marketable securities, net of tax expense of $458	-	-	-	394	394		-	394
Comprehensive income	-	-	-	-	$ 9,483			
Shares issued for oil and gas properties	1,571	16	22,175	-			-	22,191
Shares issued for drilling equipment	131	1	1,892	-			-	1,893
Shares issued for cash upon exercise of options, net	1,79318	114	-				-	132
Tax benefit on options exercised	-	-	1,255	-			-	1,255
Issuance of options below market	-	-	346	-		$ (346)	-	-
Issuance of restricted options	75	1	1,707	-		(1,708)	-	-
Amortization of unearned option compensation	-	-	-	-		672	-	672
Balance, June 30, 2005	42,017	$ 420	$ 235,300	$ (5,225)		$ (1,382)	$ (7,490)	$221,623

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended June 30,		
	2005	2004	2003
		(In thousands)	
Cash flows operating activities:			
Net income	$ 15,050	$ 5,056	$ 1,257
Adjustments to reconcile net income to cash used in operating activities:			
Depreciation and depletion	22,954	9,854	4,942
Depreciation and depletion – discontinued operations	208	328	791
Accretion of abandonment obligation	253	60	57
Stock compensation expense	672	329	124
Amortization of financing costs	858	324	456
Minority interest	(1,017)	(70)	-
Gain on sale of oil and gas properties	-	(1,887)	(277)
Unrealized loss on derivative instruments, net	331	-	-
Deferred income tax benefit, net	(3,045)	-	-
Other	394	-	20
Net changes in operating assets and operating liabilities:			
Increase in trade accounts receivable	(1,586)	(4,878)	(101)
(Increase) decrease in prepaid assets	(1,844)	(372)	21
Increase in inventory	(5,062)	(1,350)	-
(Increase) decrease in other current assets	(225)	205	(78)
Increase in accounts payable	14,004	1,361	116
Increase in other accrued liabilities	2,917	663	671
Net cash provided by operating activities	44,862	9,623	7,999
Cash flows from investing activities:			
Additions to property and equipment, net	(186,669)	(158,504)	(15,637)
Additions to drilling and trucking equipment, net	(30,797)	-	-
Proceeds from sale of oil and gas properties	18,721	10,787	850
Minority interest contributions, net	14,800	315	-
Payment on investment transaction	-	(1,022)	-
Increase (decrease) in long term assets	63	(14)	139
Net cash used in investing activities	(183,882)	(148,438)	(14,648)
Cash flows from financing activities:			
Stock issued for cash upon exercise of options	132	3,563	975
Issuance of common stock for cash	-	97,902	-
Proceeds from borrowings	361,016	69,979	9,000
Payment of financing fees	(7,370)	(368)	(354)
Repayment of borrowings	(214,595)	(32,454)	(1,725)
Net cash provided by financing activities	139,183	138,622	7,896
Net increase (decrease) in cash and cash equivalents	163	(193)	1,247
Cash at beginning of period	2,078	2,271	1,024
Cash at end of period	$ 2,241	$ 2,078	$ 2,271
Supplemental cash flow information:			
Cash paid for interest and financing costs	$ 11,420	$ 1,818	$ 1,312
Non-cash financing activities:			
Common stock issued for the purchase of oil and gas properties	$ 22,191	$ 30,526	$ 922
Common stock issued for the purchase of drilling equipment	$ 1,893	$ -	$ -

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
Notes to Consolidated Financial Statements
June 30, 2005, 2004 and 2003

(1) Nature of Organization

Delta Petroleum Corporation ("Delta" or the "Company") was organized December 21, 1984 and is principally engaged in acquiring, exploring, developing and producing oil and gas properties. The core areas of operation are the Rocky Mountain and Gulf Coast regions, which comprise the majority of our proved reserves, production and long-term growth prospects. The Company owns interests in developed and undeveloped oil and gas properties in federal units offshore California, near Santa Barbara, and developed and undeveloped oil and gas properties in the continental United States. The Company, through a series of transactions in late fiscal 2005, owns a 49.5% (Delta effectively owns an additional portion of DHS's interest until such time as the officers of DHS earn their 5.5% interest over the next five years) interest in DHS Drilling Company ("DHS"), an affiliated Colorado corporation that is headquartered in Casper, Wyoming. DHS currently has seven drilling rigs in operation that have depth ratings of approximately 7,500 to 20,000 feet. Three additional rigs are in the process of being acquired or assembled by DHS and are currently expected to become operational during the summer and fall of 2005. The Company has the right to use all of the rigs on a priority basis, although approximately half will initially work for third party operators. At the outset, all of the rigs will operate in the Rocky Mountain basins.

At June 30, 2004, the Company owned 4,277,977 shares of the common stock of Amber Resources Company ("Amber"), representing 91.68% of the outstanding common stock of Amber. Amber is a public company that owns undeveloped oil and gas properties in federal units offshore California, near Santa Barbara.

On February 19, 2002, the Company acquired 100% of the outstanding shares of Piper Petroleum Company ("Piper"), a privately owned oil and gas company headquartered in Fort Worth, Texas. Piper was merged into a subsidiary wholly owned by Delta.

(2) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Delta, Amber, Piper and DHS (collectively, the Company). All inter-company balances and transactions have been eliminated in consolidation. As Amber is in a net shareholders' deficit position for the periods presented, the Company has recognized 100% of Amber's earnings/losses for all periods. Certain reclassifications have been made to amounts reported in previous years to conform to the 2004 presentation. The Company has no interests in any other unconsolidated entities other than its investment in a liquid natural gas LLC which is recorded at its cost, nor does it have any off-balance sheet financing arrangements (other than operating leases) or any unconsolidated special purpose entities.

Certain of the Company's oil and gas activities are conducted through partnerships and joint ventures. The Company includes its proportionate share of assets, liabilities, revenues and expenses from these entities in its consolidated financial statements. Partnership net assets represent the Company's share of net working capital in such entities.

Cash Equivalents

Cash equivalents consist of money market funds. The Company considers all highly liquid investments with maturities at date of acquisition of three months or less to be cash equivalents.

(2) Summary of Significant Accounting Policies, Continued

Marketable Securities

The Company classifies its investment securities as available-for-sale securities. Pursuant to Statement of Financial Accounting Standards ("SFAS") No. 115 (SFAS 115), such securities are measured at fair market value in the financial statements with unrealized gains or losses recorded in other comprehensive income. At the time securities are sold or otherwise disposed of, gains or losses are included in earnings.

	Cost	Unrealized Gain (Loss) (In thousands)	Estimated Market Value
June 30, 2005			
Bion Environmental Technologies, Inc.	$ 152	$ (140)	$ 12
Tipperary Oil & Gas Company	418	1,334	1,752
	$ 570	$ 1,194	$ 1,764
June 30, 2004			
Bion Environmental Technologies, Inc.	$ 152	$ (138)	$ 14
Tipperary Oil & Gas Company	418	480	898
	$ 570	$ 342	$ 912
June 30, 2003			
Bion Environmental Technologies, Inc.	$ 152	$ (140)	$ 12
Tipperary Oil & Gas Company	418	232	650
	$ 570	$ 92	$ 662

Inventories

Inventories consist of pipe, other production equipment and natural gas placed in storage. Inventories are stated at the lower of cost (principally first-in, first-out) or estimated net realizable value.

Minority Interest

Minority interest represents the 50.5% (45% Chesapeake Energy Corporation, 2.75% each for William E. Sauer, Jr. and Harold D. Hastings) investors of DHS Drilling Company at June 30, 2005 and the 50% investor in Big Dog Drilling Co., LLC ("Big Dog") and Shark Trucking Co., LLC ("Shark") at June 30, 2004.

Revenue Recognition

<u>Oil and Gas</u>

Revenues are recognized when title to the products transfer to the purchaser. The Company follows the "sales method" of accounting for its natural gas and crude oil revenue, so that the Company recognizes sales revenue on all natural gas or crude oil sold to its purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. As of June 30, 2005 and 2004, the Company's aggregate natural gas and crude oil imbalances were not material to its consolidated financial statements except for an imbalance acquired during fiscal 2005 which has been collected subsequent to year end.

(2) Summary of Significant Accounting Policies, Continued

Drilling

We earn our contract drilling revenues under daywork. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. Individual wells are usually completed in less than 60 days. The cost of drilling the Company's own oil and gas properties are capitalized in oil and gas properties as the expenditures are incurred.

Property and Equipment

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under such method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for gas and oil leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed quarterly on a property-by-property basis and any impairment in value is charged to expense. If the unproved properties are determined to be productive, the related costs are transferred to proved gas and oil properties. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain or loss.

Depreciation and depletion of capitalized acquisition, exploration and development costs is computed on the units-of-production method by individual fields as the related proved reserves are produced.

Depreciation, depletion and amortization of property and equipment for the years ended June 30, 2005, 2004 and 2003 were $23.2 million, $9.9 million and $5.0 million, respectively.

Drilling equipment and other property and equipment are recorded at cost or estimated fair value upon acquisition and depreciated using the straight-line method over their estimated useful lives.

Impairment of Long-Lived Assets

Statement of Financial Accounting Standards No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144) requires that long-lived assets be reviewed for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable.

Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions and projections. If the expected future cash flows exceed the carrying value of the asset, no impairment is recognized. If the carrying value of the asset exceeds the expected future cash flows, an impairment exists and is measured by the excess of the carrying value over the estimated fair value of the asset. Any impairment provisions recognized in accordance with SFAS No. 144 are permanent and may not be restored in the future.

(2) Summary of Significant Accounting Policies, Continued

The Company assesses developed properties on an individual field basis for impairment on at least an annual basis. For developed properties, the review consists of a comparison of the carrying value of the asset with the asset's expected future undiscounted cash flows without interest costs. As a result of such assessment, the Company recorded no impairment provision attributable to producing properties for the years ended June 30, 2005, 2004 and 2003.

For undeveloped properties, the need for an impairment reserve is based on the Company's plans for future development and other activities impacting the life of the property and the ability of the Company to recover its investment. When the Company believes the costs of the undeveloped property are no longer recoverable, an impairment charge is recorded based on the estimated fair value of the property. As a result of such assessment, the Company recorded no impairment provision attributable to undeveloped properties for the years ended June 30, 2005, 2004 and 2003.

Asset Retirement Obligations

In July 2001, the Financial Accounting Standards Board ("FASB") approved for issuance SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a liability for retirement obligations of acquired assets. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on July 1, 2002 and recorded a cumulative effect of a change in accounting principle on prior years of $20,000, net of tax effects, related to the depreciation and accretion expense that would have been reported had the fair value of the asset retirement obligations, and corresponding increase in the carrying amount of the related long-lived assets, been recorded when incurred. The Company's asset retirement obligations arise from the plugging and abandonment liabilities for its oil and gas wells. The Company has no obligation to provide for the retirement of most of its offshore properties as the obligations remained with the seller. The following is a reconciliation of the Company's asset retirement obligations for the years ended June 30, 2005 and 2004.

	Years Ended June 30,	
	2005	2004
	(In thousands)	
Asset retirement obligation – beginning of period	$ 2,647	$ 868
Accretion expense	253	60
Change in estimate	-	438
Obligations acquired	1,153	1,522
Obligations settled	-	(3)
Obligations on sold properties	(362)	(238)
Asset retirement obligation – end of period	3,691	2,647
Less: Current asset retirement obligation	(716)	(105)
Long-term asset retirement obligation	$ 2,975	$ 2,542

Financial Instruments

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents and accounts receivable. The Company's cash equivalents are cash investments funds that are placed with major financial institutions. The Company manages and controls market and credit risk through established formal internal control procedures, which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure to purchasers of the Company's oil and natural gas through formal credit policies, monitoring procedures, and letters of credit.

(2) Summary of Significant Accounting Policies, Continued

The Company used various assumptions and methods in estimating fair value disclosures for financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair market value due to the short maturity of these instruments. The carrying amount of the Company's credit facility approximated fair value because the interest rates on the credit facility are variable. The fair value of long-term debt was estimated based on quoted market prices. The fair values of derivative instruments were estimated based on discounted future net cash flows.

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. It also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of Other Comprehensive Income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings.

Stock Option Plans

The Company accounts for its stock option plans in accordance with the provisions of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations. As such, compensation expense was recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. In December, 2002 the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure." SFAS 148 amends FASB Statement No. 123, "Accounting for Stock-Based Compensation" to provide alternative methods of transition for a voluntary change to the fair-value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on the reported results. The provision of SFAS 148 has no material impact on the Company, as we do not plan to adopt the fair-value method of accounting for stock options at the current time. Accordingly, no compensation cost is recognized for options granted at a price equal to or greater than the fair market value of the common stock.

Had compensation cost for the Company's stock-based compensation plan been determined using the fair value of the options at the grant date, the Company's net income for the years ended June 30, 2005, 2004 and 2003 on a proforma basis would have been as follows:

	Years Ended June 30,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Net income	$ 15,050	$ 5,056	$ 1,257
Equity compensation booked	306	-	-
FAS 123 compensation effect	(2,759)	(4,316)	(209)
Proforma net Income after FAS 123 compensation effect	$ 12,597	$ 740	$ 1,048
Proforma income per common share:			
Basic	$ .31	$ .03	$ .05
Diluted	$ .30	$ .02	$ .04

(2) Summary of Significant Accounting Policies, Continued

Income Taxes

The Company uses the asset and liability method of accounting for income taxes as set forth in Statement of Financial Accounting Standards No. 109 (SFAS No. 109), "Accounting for Income Taxes." Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and net operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted income tax rates expected to apply to taxable income in the years in which those differences are expected to be recovered or settled. Under SFAS No. 109, the effect on deferred tax assets and liabilities of a change in income tax rates is recognized in the results of operations in the period that includes the enactment date.

Earnings (Loss) per Common Share

Basic earnings (loss) per share is computed by dividing net earnings (loss) attributed to common stock by the weighted average number of common shares outstanding during each period, excluding treasury shares. Diluted earnings (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible preferred stock, stock options and warrants.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves, bad debts, oil and gas properties, depletion and impairment, marketable securities, income taxes, derivatives, asset retirement obligations, contingencies and litigation. Actual results could differ from these estimates.

Recently Issued Accounting Standards and Pronouncements

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3* ("Statement 154"). SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS 154 also requires that a change in depreciation, amortization, or depletion method for long-lived, non-financial assets be accounted for as a change in accounting estimate affected by a change in accounting principle. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The implementation of FAS 154 is not expected to have a material impact on the Company's consolidated results of operations, financial position or cash flows.

(2) Summary of Significant Accounting Policies, Continued

In December 2004, the FASB issued its final standard on accounting for employee stock options, FAS No. 123 (Revised 2004), "Share-Based Payment" ("FAS123(R)"). FAS 123(R) replaces FAS No. 123, "Accounting for Stock-Based Compensation" ("FAS 123"), and supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." FAS 123(R) requires companies to measure compensation costs for all share-based payments, including grants of employee stock options, based on the fair value of the awards on the grant date and to recognize such expense over the period during which an employee is required to provide services in exchange for the award. The pro forma disclosures previously permitted under FAS 123 will no longer be an alternative to financial statement recognition. FAS 123(R) is effective for all awards granted, modified, repurchased or cancelled after, and to unvested portions of previously issued and outstanding awards vesting after, interim or annual periods, beginning after June 15, 2005, which for us will be the first quarter of fiscal 2006. The Company is currently evaluating the effect of adopting FAS 123(R) on its financial position and results of operations, and have not yet determined whether the adoption of FAS 123(R) will result in expenses in amounts that are similar to the current pro forma disclosures under FAS 123.

In February 2005, the staff of the Securities and Exchange Commission sent a letter to oil and gas registrants regarding situations that require additional financial statement disclosures, pending final resolution of accounting treatment. The following are items related to registrants using the successful efforts method of accounting:

- Companies may enter concurrent commodity buy/sale arrangements, or transactions in contemplation of other transactions, often to assure that the commodity is available at a specific location. Pending resolution of accounting questions with the Emerging Issues Task Force, the Commission staff has requested additional disclosures for any such material arrangements, including separate disclosure on the face of the income statement of any related proceeds and costs reported on a gross basis. These disclosures are not applicable to the Company since we have not entered any significant transactions of this nature.

- Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, specifies that drilling costs for completed exploratory wells should be expensed if the related reserves cannot be classified as proved within one year unless certain criteria are met. In April 2005, the FASB issued FASB Staff Position 19-1, Accounting for Suspended Well Costs. FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, however, early application is permitted. Pending adoption of FSP 19-1, the Commission staff has requested additional disclosures be included in registrants' financial statements regarding their accounting policy for capitalization of exploratory drilling costs, as well as disclosure of capitalized exploratory drilling cost amounts included in the financial statements. The Company generally pursues development of proved reserves as opposed to exploration activities, and drill well costs are generally transferred to producing properties within one month of the well completion date.

(2) Summary of Significant Accounting Policies, Continued

In December 2004, the FASB issued its final standard on accounting for employee stock options, FAS No. 123 (Revised 2004), "Share-Based Payment" ("FAS123(R)"). FAS 123(R) replaces FAS No. 123, "Accounting for Stock-Based Compensation" ("FAS 123"), and supersedes Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees". FAS 123(R) requires companies to measure compensation costs for all share-based payments, including grants of employee stock options, based on the fair value of the awards on the grant date and to recognize such expense over the period during which an employee is required to provide services in exchange for the award. The pro forma disclosures previously permitted under FAS 123 will no longer be an alternative to financial statement recognition. FAS 123(R) is effective for all awards granted, modified, repurchased or cancelled after, and to unvested portions of previously issued and outstanding awards vesting after, interim or annual periods beginning after June 15, 2005, which for us will be the first quarter of fiscal 2006. We are currently evaluating the effect of adopting FAS 123(R) on our financial position and results of operations, and we have not yet determined whether the adoption of FAS 123(R) will result in expenses in amounts that are similar to the current pro forma disclosures under FAS 123.

(3) Oil and Gas Properties

Unproved Undeveloped Offshore California Properties

The Company has ownership interests ranging from 2.49% to 75% in five unproved undeveloped offshore California oil and gas properties with aggregate carrying values of $10.9 million and $10.8 million at June 30, 2005 and 2004, respectively. These property interests are located in proximity to existing producing federal offshore units near Santa Barbara, California and represent the right to explore for, develop and produce oil and gas from offshore federal lease units. Preliminary exploration efforts on these properties have occurred and the existence of substantial quantities of hydrocarbons has been indicated. The recovery of the Company's investment in these properties will require extensive exploration and development activities (and costs) that cannot proceed without certain regulatory approvals that have been delayed and is subject to other substantial risks and uncertainties as discussed herein.

The Company is not the designated operator of any of these properties but is an active participant in the ongoing activities of each property along with the designated operator and other interest owners. If the designated operator elected not to or was unable to continue as the operator, the other property interest owners would have the right to designate a new operator as well as share in additional property returns prior to the replaced operator being able to receive returns. Based on the Company's size, it would be difficult for the Company to proceed with exploration and development plans should other substantial interest owners elect not to proceed. However, to the best of its knowledge, the Company believes the designated operators and other major property interest owners intend to proceed with exploration and development plans under the terms and conditions of the operating agreement.

Even though the Company is not the designated operator of the properties and regulatory approvals have not been obtained, the Company believes exploration and development activities on these properties will occur and is committed to expend funds attributable to its interests in order to proceed with obtaining the approvals for the exploration and development activities.

(3) Oil and Gas Properties, Continued

Based on the preliminary indicated levels of hydrocarbons present from drilling operations conducted in the past, the Company believes the fair value of its property interests are in excess of their carrying value at June 30, 2005 and June 30, 2004 and that no impairment in the carrying value has occurred. Should the required regulatory approvals not be obtained or plans for exploration and development of the properties not continue, the carrying value of the properties would likely be impaired and written off.

The forty undeveloped leases are located in the Offshore Santa Maria Basin off the coast of Santa Barbara and San Luis Obispo counties, and in the Santa Barbara Channel off Santa Barbara and Ventura counties. The ownership rights in each of these properties have been retained under various suspension notices issued by the Mineral Management Service (MMS) of the U.S. Federal Government whereby, as long as the owners of each property were progressing toward defined milestone objectives, the owners' rights with respect to the properties continue to be maintained. The issuance of the suspension notices has been necessitated by the numerous delays in the exploration and development process resulting from regulatory requirements imposed on the property owners by federal, state and local agencies.

On June 22, 2001, however, a Federal Court in the case of California v. Norton, et al. ruled that the MMS does not have the power to grant suspensions on the subject leases without first making a consistency determination under the Coastal Zone Management Act ("CZMA"), and ordered the MMS to set aside its approval of the suspensions of the Company's offshore leases and to direct suspensions for a time sufficient for the MMS to provide the State of California with the required consistency determination. The delays have prevented the property owners from submitting for approval an exploration plan on four of the properties. If and when plans are submitted for approval, they are subject to review for consistency with the CZMA, and by the MMS for other technical requirements.

As the ruling in the Norton case currently stands, the United States has made a consistency determination under the CZMA in accordance with the Court's order and the leases are still valid. If the leases are found not to be valid for some reason in the future, it would appear that the leases would become impaired even though the Company would undoubtedly proceed with its litigation. It is also possible that other events could occur that would cause the leases to become impaired, and the Company will continuously evaluate those factors as they occur.

None of these leases is currently impaired, but in the event that there is some future adverse ruling by the California Coastal Commission under the CZMA and the Company decides not to appeal such ruling to the Secretary of Commerce, or the Secretary of Commerce either refuses to hear the Company's appeal of any such ruling or ultimately makes an adverse determination, it is likely that some or all of these leases would become impaired and written off at that time.

On January 9, 2002, the Company and several other plaintiffs filed a lawsuit in the United States Court of Federal Claims in Washington, D.C. alleging that the U.S. Government has materially breached the terms of the forty undeveloped federal leases, some of which are part of the Company's Offshore California properties. The Complaint is based on allegations by the collective plaintiffs that the United States has materially breached the terms of certain of their Offshore California leases by attempting to deviate significantly from the procedures and standards that were in effect when the leases were entered into, and by failing to carry out its own obligations relating to those leases in a timely and fair manner. More specifically, the plaintiffs have alleged that the judicial determination in the Norton case that a 1990 amendment to the CZMA required the DELTA Government to make a consistency determination prior to granting lease suspension requests in 1999 constitutes a material change in the procedures and standards that were in effect when the leases were issued.

(3) Oil and Gas Properties, Continued

The plaintiffs have also alleged that the United States has failed to afford them the timely and fair review of their lease suspension requests which has resulted in significant, continuing and material delays to their exploratory and development operations.

The suit seeks compensation for the lease bonuses and rentals paid to the Federal Government, exploration costs and related expenses. The total amount claimed by all lessees for bonuses and rentals exceeds $1.2 billion, with additional amounts for exploration costs and related expenses. The Company's claim for lease bonuses and rentals paid by it and its predecessors is in excess of $152.0 million. In addition, the Company's claim for exploration costs and related expenses will also be substantial. In the event, however, that the Company receives any proceeds as the result of such litigation, it will be obligated to pay a portion of any amount received by it to landowners and other owners of royalties and similar interests, and to pay expenses of litigation and to fulfill certain pre-existing contractual commitments to third parties.

Fiscal 2005 and 2004 – Significant Acquisitions

On December 15, 2004, the Company entered into a purchase and sale agreement to acquire substantially all of the oil and gas assets owned by several entities related to Manti Resources, Inc., which was an unaffiliated, privately held Texas corporation ("Manti"). The adjusted purchase price of $59.7 million was paid in cash at the closing of the transaction, which occurred on January 21, 2005. The purchase price for the Manti properties was determined through arms-length negotiations. The purchase price was paid with increased borrowings on the Company's bank credit facility. Substantially all of the assets that we acquired from Manti have been pledged as collateral for we bank credit facility.

On June 29, 2004, the Company completed the acquisition of substantially all of the oil and gas assets owned by several entities controlled by Alpine Resources, Inc. ("Alpine") for $122.5 million, which was funded with $68.4 million in net proceeds that the Company received from a $72.0 million private placement of 6 million shares of its restricted common stock to institutional investors at a purchase price of $12.00 per share, and from borrowings of $54.1 million under its senior credit facility. On August 19, 2004 the Company sold a portion of these assets to Whiting Petroleum Corporation for $18.7 million in net proceeds. There was no gain or loss on the sale of these assets.

The following unaudited pro forma condensed consolidated statement of operations information assumes that the Manti and Alpine property acquisitions occurred as of July 1, 2003:

	Years Ended June 30,	
	2005	2004
	(In thousands)	
Oil and gas sales	$113,059	$ 86,272
Net earnings from continuing operations, net of tax	$ 19,142	$ 15,514
Net earnings from continuing operations per common share, net of tax:		
Basic	$ .47	$ .47
Diluted	$ .46	$ .44

(3) Oil and Gas Properties, Continued

The above unaudited condensed pro forma consolidated statements of operations information, based on the historical producing property operating results of Manti, Alpine and Delta, are not necessarily indicative of the results of operations if Delta would have acquired the Manti and Alpine properties at July 1, 2003.

Fiscal 2005 - Additional Acquisitions

On September 15, 2004, the Company acquired seven wells in Karnes County, Texas from an unrelated entity and an unrelated individual for $5.0 million in cash.

On July 1, 2004, the Company acquired certain interests in California's Sacramento Basin and a 7.5% reversionary working interest in the South Tongue interests in Washington County, Colorado from Edward Mike Davis, LLC, a greater than 5% shareholder ("Davis"), for 760,000 shares of the Company's common stock valued at $10.4 million using the average five-day closing price before and after the terms of the agreement were agreed upon and closed. The total acquisition cost was allocated $4.3 million to proved developed producing and $6.1 million to proved undeveloped.

On May 4, 2005, the Company purchased from an unrelated private company a 14.25% back-in working interest in approximately 427,000 acres in the Columbia River Basin for $18.2 million in cash. The acreage is in close proximity to many of its existing leasehold interests in the basin and includes a lease on which another operator is currently drilling. The interest acquired is a non-cost bearing interest with a back-in after project payout. The Company can, however, at any time and at its discretion, convert the interest to a cost-bearing working interest by paying its proportionate share of the costs incurred in the project.

Fiscal 2004 - Additional Acquisitions

During fiscal 2004 the Company made other producing property acquisitions in North Dakota of approximately 2.4 Bcfe for a total consideration of $4.2 million through the issuance 773,500 shares of the Company's common stock.

During the period from September of 2003 through July of 2004 the Company completed a series of transactions with Edward Mike Davis and certain unrelated individuals which resulted in an acquisition of a producing property and approximately 360,000 acres of undeveloped properties in the Company's North and South Tongue prospects located in Washington and Yuma Counties, Colorado, and an interest in producing and non-producing properties located in Colusa, Orange and Los Angeles Counties, California. Through these acquisitions the Company obtained an aggregate of approximately 6 Bcfe in proved producing reserves and a significant drilling inventory for a total consideration of approximately $8.0 million in cash and 2,551,000 shares of the Company's common stock.

During fiscal 2004, the Company invested an aggregate of $1.0 million for a 6.25% interest as a member of Crystal Energy, LLC, which is an unaffiliated Delaware limited liability company that is currently in the process of attempting to obtain the rights to own and operate a liquid natural gas facility from Platform Grace, which is an existing platform located offshore California. If the limited liability company is successful in obtaining these rights, it intends to engage in the business of accepting and vaporizing liquid natural gas delivered by liquid natural gas tankers, transporting the vaporized liquid natural gas through proprietary gas pipelines and selling the vaporized natural gas to third party customers located in California. As of June 30, 2005, the limited liability company had not yet engaged in any revenue producing activities.

Fiscal 2003 - Acquisitions

On June 20, 2003, the Company acquired producing oil and gas interests and related undeveloped acreage in Kansas from JAED Production Company for total consideration of $8.7 million net of normal closing adjustments. On the date of acquisition, the Company estimated proved reserves to be approximately 9.9 Bcfe.

(3) Oil and Gas Properties, Continued

Discontinued Operations

In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the results of operations and gain (loss) relating to the sale of the following property interests have been reflected as discontinued operations.

On August 19, 2004, the Company completed the sale of certain interests in five fields in Louisiana and South Texas previously acquired in the Alpine acquisition, which closed on June 29, 2004, to Whiting Petroleum Corporation for $18.7 million, net of certain commissions. The Company paid $8.8 million toward its credit facility from the proceeds of the sale of these properties. There was no gain or loss on this sale transaction and the net profit earned on these assets during the quarter, since the acquisition, of $729,000 has been shown in discontinued, operations net of taxes of $280,000.

On March 31, 2004, the Company completed the sale of all of its Pennsylvania properties to Castle Energy Corporation, a 25% shareholder of Delta at March 31, 2004, for cash consideration of $8 million, which the Company believes is fair value, with an effective date of January 1, 2004 and resulted in a gain on sale of oil and gas properties of $1.9 million. Revenues from the sale of these oil and gas properties were approximately $1.2 million for the nine months ended March 31, 2004 and $1.8 million for the year ended June 30, 2003.

On December 5, 2003, the Company completed the sale of certain properties located in Texas to Sovereign Holdings, LLC for cash consideration of $2.6 million. The effective date of the transaction was January 1, 2004 and it resulted in a loss on the sale of oil and gas properties of $28,000. Revenues attributed to the sale of these oil and gas properties were approximately $537,000 for the nine months ended March 31, 2004 and $1.2 million for the year ended June 30, 2003.

During the year ended June 30, 2003, the Company disposed of additional non-strategic oil and gas properties and related equipment to unaffiliated entities in addition to the dispositions described above. The Company has received proceeds from these sales of $850,000 and such sales resulted in a net gain on sale of oil and gas properties of $277,000 for the year ended June 30, 2003.

(4) DHS Drilling Company

On April 4, 2005, the Company acquired a 49.5% ownership interest in DHS Drilling Company. The investment includes all of the net assets of the then 100% owned subsidiary, Big Dog, and certain drilling assets acquired by the Company. On March 31, 2005, the Company purchased the remaining 50% interest of Big Dog owned by Davis for 100,000 shares of the Delta's common stock valued at $1.4 million based on the closing stock price on March 31, 2005, its 50% interest in Shark and certain drilling equipment. DHS currently has seven drilling rigs in operation that have depth ratings of approximately 7,500 to 20,000 feet. Three additional rigs are in the process of being acquired or assembled by DHS and are currently expected to become operational during the summer and fall of 2005. The Company has the right to use all of the rigs on a priority basis, although approximately half will initially work for third party operators. At the outset, all of the rigs will operate in the Rocky Mountain basins.

(5) Long Term Debt

7% Senior Notes, Due 2015, Unsecured

On March 15, 2005, the Company issued 7% senior unsecured notes for an aggregate amount of $150.0 million which pay interest semiannually on April 1 and October 1 and mature in 2015. The net proceeds were used to refinance debt outstanding under our credit facility which included the amount required to acquire the Manti properties. The notes were issued at 99.50% of par and the associated discount is being amortized to interest expense over the term of the notes. The indenture governing the notes contains various restrictive covenants that may limit the Company's and its subsidiaries ability to, among other things, incur additional indebtedness, make certain investments, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and restricted subsidiaries. These covenants may limit the discretion of the Company's management in operating the Company's business. The Company was in compliance with these covenants as of June 30, 2005. See "Guarantee of Financial Information" footnote below (Footnote 12). The fair value of the Company's senior notes at June 30, 2005 was $141.0 million.

Credit Facility

On June 30, 2005, the Company amended its credit facility with Bank One, N.A., Bank of Oklahoma N.A., U.S. Bank National Association and Hibernia National Bank (the "Banks"). At June 30, 2005, the $200.0 million credit facility had an available borrowing base of approximately $75.0 million and $66.5 million outstanding. The reduction in available borrowing base was established until certain drilling results were attained. The Company anticipates our available borrowing base to increase with future drilling success. The facility has variable interest rates based upon the ratio of outstanding debt to the borrowing base. Rates vary between prime + .25% and 1.00% for base rate loans and between Libor + 1.5% and 2.25% for Eurodollar loans. The rate at June 30, 2005 approximated 7%. The loan was collateralized by substantially all of our oil and gas properties. Currently, we are required to meet certain financial covenants which include a current ratio of 1 to 1, net of derivative instruments of $7 million and a consolidated debt to EBITDAX (earnings before interest, taxes, depreciation, amortization and exploration) of less than 3.5 to 1. The financial covenants only include subsidiaries which the Company owns 100%. At June 30, 2005 the Company was not in compliance with its quarterly debt covenants and restrictions, but obtained a waiver from the banks for the quarter ended June 30, 2005.

Kaiser Francis Oil Company - Debt

On December 1, 1999, the Company borrowed $8 million at prime plus 1-1/2% from Kaiser Francis Oil Company. The proceeds from this loan were used to pay off existing debt and the balance of the Point Arguello Unit and New Mexico acquisitions. During the third quarter of fiscal 2004, the loan was paid in full.

Maturities of long-term debt, in thousands of dollars based on contractual terms are as follows:

YEAR ENDING June 30,	
2006	$ 3,477
2007	149
2008	72
2009	66,508
2010	-
Thereafter	150,000
	$ 220,206

(6) Stockholders' Equity

Preferred Stock

The Company has 3,000,000 shares of preferred stock authorized, par value $.10 per share, issuable from time to time in one or more series. As of June 30, 2005, 2004 and 2003, no preferred stock was issued.

Common Stock

The Company raised additional capital through the sale of shares of its common stock, net of commissions, of $97.9 million for the year ended June 30, 2004. Offering costs of $6.1 million consisted of cash commissions and legal services relating to the transactions and were accounted for as an adjustment to stockholders' equity. The Company did not raise cash through the issuance of shares of its common stock during the years ended June 30, 2005 and 2003.

During the years ended June 30, 2005, 2004 and 2003, the Company acquired oil and gas properties for 1,571,000, 3,728,000, and 200,000 shares of the Company's common stock, respectively. The shares were valued at $22.2 million, $30.5 million and $922,000, respectively.

During fiscal 2005, the Company acquired drilling equipment for 131,000 shares of the Company's common stock valued at $1.9 million.

Non-Qualified Stock Options - Directors and Employees

On May 31, 2002 at the annual meeting of the shareholders, the shareholders ratified the Company's 2002 Incentive Plan (the "Incentive Plan") under which it reserved up to an additional 2,000,000 shares of common stock. This plan supercedes the Company's 1993 and 2001 Incentive Plans.

Incentive awards under the Incentive Plan may include non-qualified or incentive stock options, limited appreciation rights, tandem stock appreciation rights, phantom stock, stock bonuses or cash bonuses. Options issued to date under the Company's various incentive plans have been non-qualified stock options as defined in such plans. Options are generally issued at market price at the date of grant with various vesting and expiration terms based on the discretion of the Incentive Plan Committee.

A summary of the stock option activity under the Company's various plans and related information for the years ended June 30, 2005, 2004 and 2003 follows:

	2005		2004		2003	
		Weighted-Average Exercise		Weighted-Average Exercise		Weighted-Average Exercise
	Options	Price	Options	Price	Options	Price
Outstanding-beginning of year	4,700,772	$ 4.10	3,410,987	$ 3.15	3,378,487	$ 3.07
Granted	1,034,700	14.71	1,736,000	5.63	255,000	2.79
Exercised	(2,189,071)	(3.33)	(435,215)	(2.51)	(217,500)	1.59)
Expired / Returned	(45,000)	(14.37)	(11,000)	(6.39)	(5,000)	(3.20)
Outstanding-end of year	3,501,401	$ 7.59	4,700,772	$ 4.10	3,410,987	$ 3.15
Exercisable-end of year	1,580,534	$ 5.01	4,300,772	$ 4.11	3,240,987	$ 3.15

(6) Stockholders' Equity, Continued

The Company has issued options to its Non-employee Directors and recorded stock option expense in the amount of $329,000 and $114,000 for the years ended June 30, 2004 and 2003, respectively, for options issued below market prices.

Exercise prices for options outstanding under the Company's various plans as of June 30, 2005 ranged from $1.13 to $15.46 per share. The weighted-average remaining contractual life of those unvested options is 5.95 years. At June 30, 2005 1,920,867 options were unvested. A summary of the outstanding and exercisable options at June 30, 2005, segregated by exercise price ranges, is as follows:

Exercise Price Range	Options Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (in years)	Exercisable Options	Weighted Average Exercise Price
$1.13 - $ 3.25	590,951	$2.28	5.23	590,951	$2.28
$3.26 - $15.46	2,910,450	$8.67	6.80	989,583	$6.65

The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted-average assumptions for the years ended June 30, 2005, 2004 and 2003, respectively, risk-free interest rates of 4.28%, 4.32% and 2.84%, dividend yields of 0%, 0% and 0%, volatility factors of the expected market price of the Company's common stock of 43.97%, 50.43% and 65.32% and a weighted-average expected life of the options of 4.76, 5.56 and 4.16 years. The fair value of the options granted at the grant date is $8.0 million, $10.2 million and $713,000 for the years ended June 30, 2005, 2004 and 2003, respectively.

Non-Qualified Stock Options (Non-Employee)

The Company has also issued options to non-employees and recorded stock option expense in the amount of $10,000 to non-employees for the year ended June 30, 2003 and none for the years ended June 30, 2005 and 2004.

A summary of the stock option and warrant activity and related information for the years ended June 30, 2005, 2004 and 2003 is as follows:

	2005		2004		2003	
		Weighted-Average Exercise		Weighted-Average Exercise		Weighted-Average Exercise
	Options	Price	Options	Price	Options	Price
Outstanding-beginning of year	57,500	$ 3.80	1,255,000	$ 3.38	1,954,000	$ 3.62
Granted	-	-	-	-	-	-
Exercised	57,500	3.80	(1,197,500)	(2.48)	(250,761)	(2.51)
Expired	-	-	-	-	(448,239)	(4.76)
Outstanding-end of year	-	$ -	57,500	$ 3.80	1,255,000	$ 3.38
Exercisable at end of year	-	$ -	57,500	$ 3.80	1,255,000	$ 3.38

(7) Employee Benefits

The Company adopted a profit sharing plan on January 1, 2002. All employees are eligible to participate and contributions to the profit sharing plan are voluntary and must be approved by the Board of Directors. Amounts contributed to the Plan will vest over a six year service period.

The Company adopted a 401k plan effective May 1, 2005. All employees are eligible to participate and make employee contributions once they have met the plan's eligibility criteria. Under the 401k plan, the Company's employees make salary reduction contributions in accordance with the Internal Revenue Service guidelines. The Company's matching contribution is an amount equal to 100% of the employee's elective deferral contribution which cannot exceed 3% of the employee's compensation, and 50% of the employee's elective deferral which exceeds 3% of the employee's compensation but does not exceed 5% of the employee's of the employee's compensation.

For the years ended June 30, 2005, 2004 and 2003 the Company contributed $291,000, $262,000 and $147,000, respectively, under the plans.

(8) *Commodity Derivative Instruments and Hedging Activities*

The Company periodically enters into commodity price risk transactions to manage its exposure to oil and gas price volatility. These transactions may take the form of futures contracts, collar agreements, swaps or options. The purpose of the hedges is to provide a measure of stability to the Company's cash flows in an environment of volatile oil and gas prices. All transactions are accounted for in accordance with requirements of SFAS No. 133 which the Company adopted on January 1, 2001. Accordingly, unrealized gains and losses related to the change in fair market value of derivative contracts which qualify and are designated as cash flow hedges are recorded as other comprehensive income or loss, to the extent the hedge is effective, and such amounts are reclassified to realized gain (loss) on derivative instruments as the associated production occurs.

At June 30, 2005, all of the Company's derivative contracts are collars. Under a collar agreement the Company receives the difference between the floor price and the index price only when the index price is below the floor price; and the Company pays the difference between the ceiling price and the index price only when the index price is above the ceiling price. The Company's collars are settled in cash on a monthly basis. By entering into collars, the Company effectively provides a floor for the price that it will receive for the hedged production, however, the collar also establishes a maximum price that the Company will receive for the hedged production when prices increase above the ceiling price. The Company enters into collars during periods of volatile commodity prices in order to protect against a significant decline in prices in exchange for forgoing the benefit of price increases in excess of the ceiling price on the hedged production.

Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at market value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current income or expense in the consolidated statement of operations. While such derivative contracts do not qualify for hedge accounting, management believes these contracts can be utilized as an effective component of commodity price risk activities.

(8) Commodity Derivative Instruments and Hedging Activities, Continued

The following table summarizes our derivative contracts, which have been designated as hedges, at June 30, 2005:

Commodity	Volume		Price Floor / Price Ceiling		Term	Index	Fair Value at June 30, 2005 (In thousands)
Crude oil	6,000	Bbls / month	$ 35.00 /	$ 49.75	Apr '05 - Dec '05	NYMEX-WTI	$ 335
Crude oil	40,000	Bbls / month	$ 40.00 /	$ 50.34	July '05 - June '06	NYMEX-WTI	4,629
Crude oil	10,000	Bbls / month	$ 45.00 /	$ 56.90	July '05 - June '06	NYMEX-WTI	599
Crude oil	25,000	Bbls / month	$ 35.00 /	$ 61.80	July '06 - June '07	NYMEX-WTI	1,681
Natural gas	3,000	MMBtu / day	$ 5.00 /	$ 7.85	Apr '05 - Oct '05	NYMEX-H HUB	40
Natural gas	10,000	MMBtu / day	$ 5.00 /	$ 9.60	July '05 - June '06	NYMEX-H HUB	995
Natural gas	3,000	MMBtu / day	$ 6.00 /	$ 9.35	July '05 - June '06	NYMEX-H HUB	255
Natural gas	13,000	MMBtu / day	$ 5.00 /	$ 10.20	July '06 - June '07	NYMEX-H HUB	1,466
							$ 10,000

The fair value of the Company's net derivative instruments obligation was a liability of approximately $10.0 million at June 30, 2005 and $23.3 million on September 12, 2005.

The net losses from hedging activities recognized in the Company's statements of operations were $960,000, $859,000 and $1.9 million for the years ended June 30, 2005, 2004 and 2003, respectively. These losses are recorded as a decrease in revenues. During the year ended June 30, 2005, $330,000 of losses realized from ineffectiveness on hedging activities were reclassified from other comprehensive income into realized loss on derivative instruments in the statement of operations. Based on the estimated fair value of the derivative contracts at June 30, 2005, the Company expects to reclassify net losses of $7.2 million into earnings related to derivative contracts during the next twelve months; however, actual gains and loses recognized may differ materially.

(9) Income Taxes

The Company accounts for income taxes in accordance with the provisions of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes ("SFAS" 109). Income tax expense (benefit) attributable to income from continuing operations consisted of the following for the years ended June 30, 2005, 2004 and 2003.

	Years Ended June 30,		
	2005	2004 (In thousands)	2003
CURRENT:			
U.S. - Federal	$ -	$ -	$ -
U.S. - State	-	-	-
Foreign	-	-	-
DEFERRED:			
U.S. - Federal	(3,027)	-	-
U.S. - State	(298)	-	-
Foreign	-	-	-
	$ (3,325)	$ -	$ -

Income from continuing operations before taxes consists of the following for the years ended June 30, 2005, 2004 and 2003.

	2005	2004	2003
Income from continuing operations before taxes	$ 11,276	$ 5,056	$ 1,257

(9) Income Taxes, Continued

Income tax expense attributable to income from continuing operations was different from the amounts computed by applying U.S. Federal income tax rate of 35% to pretax income from continuing operations as a result of the following:

	Years Ended June 30,		
	2005	2004	2003
Federal statutory rate	35.00 %	35.00 %	35.00 %
State income taxes, net of federal benefit	3.44 %	3.10 %	2.50 %
Investment in DHS	3.53 %	0.25 %	0.25 %
Change in valuation allowance	(69.63) %	(38.35) %	(37.75) %
Other	(1.83) %	-	-
Actual income tax rate	(29.49) %	0.00 %	0.00 %

Deferred tax assets (liabilities) are comprised of the following at June 30, 2005 and 2004:

	Years Ended June 30,	
	2005	2004
	(In thousands)	
Current deferred tax assets		
Derivative instruments	$ 2,638	$ -
Allowance for doubtful accounts	38	19
Total current deferred tax assets	2,676	19
Less valuation allowance	-	(19)
Net current deferred tax asset	$ 2,676	$ -
Long-term deferred tax assets (liability):		
Deferred tax assets:		
Net operating loss	$ 14,544	$ 13,278
Asset retirement obligation	1,419	1,009
Derivative instruments	1,211	-
Percentage depletion	541	-
Drilling equipment	403	-
Other	66	-
Total long-term deferred tax assets	18,184	14,287
Valuation allowance	(1,139)	(8,971)
Net deferred tax asset	17,045	5,316
Deferred tax liabilities:		
Oil and gas properties	(11,256)	(5,316)
Investment in DHS	(399)	-
Investments – available for sale	(503)	-
Total long-term deferred tax liabilities	(12,158)	(5,316)
Net long-term deferred tax asset (liability)	$ 4,887	$ -

(9) Income Taxes, Continued

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future table income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that the Company will realize the benefits of these deductible differences, net of the existing valuation allowances at June 30, 2005. The valuation allowance at June 30, 2005 relates primarily to a subsidiary's net operating loss that cannot be used to reduce taxable income generated by other members of the consolidated tax group and a deferred tax asset generated by a subsidiary that is not consolidated for tax purposes and does not have a history of earnings. The amount of the deferred tax asset considered realizable could be reduced if estimates of future taxable income during the carry-forward period are reduced.

The Company's net operating losses are scheduled to expire as follows (in thousands):

2006	$ 318
2007	322
2008	346
2009	1,827
2010	720
2011 and thereafter	33,757
	$37,290

(10) Related Party Transactions

Transactions with Officers

Until March 12, 2003, the Company's Board of Directors had granted each of our officers the right to participate in the drilling, on the same terms as the Company, in up to a five percent (5%) working interest in any well drilled, re-entered, completed or re-completed by us on our acreage (provided that any well to be re-entered or re-completed was then producing economic quantities of hydrocarbons). On March 12, 2003, the Board of Directors rescinded this right. The officers did not participate in any Company wells during fiscal 2003.

During fiscal 2001 and 2000, Mr. Larson and Mr. Parker guaranteed certain borrowings which have subsequently been paid in full. As consideration for the guarantee of the Company's indebtedness, each officer was assigned a 1% overriding royalty interest ("ORRI") in the properties acquired with the proceeds of the borrowings. Each officer earned approximately $100,000, $66,000 and $108,000 for their respective 1% ORRI during fiscal 2005, 2004 and 2003, respectively.

The Company's officers have employment agreements which, among other things, include termination and change of control clauses.

Accounts Receivable Related Parties

At June 30, 2005, the Company had $32,000 of receivables from related parties. These amounts include drilling costs and lease operating expense on wells owned by the related parties and operated by the Company.

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(11) Earnings Per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Years Ended June 30,		
	2005	2004	2003
		(In thousands, except per share amounts)	
Numerator:			
Numerator for basic and diluted earnings per share – income available to common stockholders	$ 15,050	$ 5,056	$ 1,257
Denominator:			
Denominator for basic earnings per share-weighted average shares outstanding	40,327	27,041	22,865
Effect of dilutive securities, stock options and warrants	1,693	2,591	954
Denominator for diluted earnings per common share	42,020	29,632	23,819
Basic earnings per common share	$ .37	$ .19	$ .05
Diluted earnings per common share	$ .36	$ .17	$ .05

(12) Guarantee of Financial Information

Delta ("Issuer") issued 7% Senior Notes ("Bond Offering") on March 15, 2005, for the aggregate amount of $150.0 million, which pay interest semiannually on April 1st and October 1st and mature in 2015. The proceeds were used to refinance debt outstanding under the Company's credit facility. This Bond Offering is guaranteed by all of the 100% owned subsidiaries of the Company at the time of the Bond Offering ("Guarantors"). The Guarantors, fully, jointly and severally, irrevocably and unconditionally guarantee the performance and payment when due of all the obligations under the Bond Offering. Big Dog, Shark, DHS and Amber ("Non-guarantors") are not guarantors of the indebtedness under the Bond Offering.

The following financial information sets forth the Company's condensed consolidating balance sheets as of June 30, 2005 and 2004, the condensed consolidating statements of operations for the years ended June 30, 2005, 2004 and 2003 and the condensed consolidating statements of cash flows for years ended June 30, 2005, 2004 and 2003 (in thousands).

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(12) Guarantee of Financial Information, Continued

Condensed Consolidated Balance Sheet
June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 23,602	$ 2,235	$ 1,197	$ -	$ 27,034
Property and equipment:					
Oil and gas	455,678	6,556	5,007		467,241
Drilling rigs and trucks	-	-	40,031	-	40,031
Other	10,347	-	65	-	10,412
Total property and equipment	466,025	6,556	45,103	-	517,684
Accumulated DD&A	(42,003)	(1,032)	(1,099)	-	(44,134)
Net property and equipment	424,022	5,524	44,004	-	473,550
Investment in subsidiaries	26,322	-	-	(26,322)	-
Other long-term assets	12,359	-	40	-	12,399
Total assets	$486,305	$ 7,759	$ 45,241	$ (26,322)	$ 512,983
Current liabilities	$ 42,294	$ 215	$ 11,641	$ -	$ 54,150
Long-term liabilities					
Long-term debt	219,437	-	184	-	219,621
Asset retirement obligation	2,951	24	-	-	2,975
Total long-term liabilities	222,388	24	184	-	222,596
Minority interest	14,614	-	-	-	14,614
Shareholders' equity	207,009	7,520	33,416	(26,322)	221,623
Total liabilities and shareholders' equity	$486,305	$ 7,759	$ 45,241	$ (26,322)	$ 512,983

(12) Guarantee of Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 88,254	$ 1,657	$ 7,319	$ (2,523)	$ 94,707
Operating expenses:					
Lease operating expense	21,780	489	-	-	22,269
Depreciation and depletion	21,534	148	1,525	-	23,207
Exploration expense	6,155	-	-	-	6,155
Drilling and trucking operations	-	-	6,799	(2,133)	4,666
Dry hole, abandonment and impaired	2,771	-	-	-	2,771
General and administrative	15,788	9	1,133	-	16,930
Total expenses	68,028	646	9,457	(2,133)	75,998
Income (loss) from continuing operations	20,226	1,011	(2,138)	(390)	18,709
Other income and expenses	(7,462)	31	(2)	-	(7,433)
Income tax benefit	3,325	-	-	-	3,325
Discontinued operations	449	-	-	-	449
Net income (loss)	$ 16,538	$ 1,042	$ (2,140)	$ (390)	$ 15,050

Condensed Consolidated Statement of Cash Flows
Year Ended June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 37,057	$ 707	$ 7,098	$ 44,862
Investing activities	(158,273)	(551)	(25,058)	(183,882)
Financing activities	121,262	-	17,921	139,183
Net increase (decrease) in cash and cash equivalents	46	156	(39)	163
Cash at beginning of the period	1,992	40	46	2,078
Cash at the end of the period	$ 2,038	$ 196	$ 7	$ 2,241

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(12) Guarantee of Financial Information, Continued

Condensed Consolidated Balance Sheet
Year Ended June 30, 2004

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 13,781	$ 1,115	$ 57	$ -	$ 14,953
Property and equipment:					
Oil and gas	261,879	6,007	5,006	-	272,892
Drilling rigs and trucks	-	-	3,965	-	3,965
Other	1,136	-	11	-	1,147
Total property and equipment	263,015	6,007	8,982	-	278,004
Accumulated DD&A	(20,765)	(886)	(14)	-	(21,665)
Net property and equipment	242,250	5,121	8,968	-	256,339
Investment in subsidiaries	14,724	-	-	(14,724)	-
Other long-term assets	1,412	-	-	-	1,412
Total assets	$272,167	$ 6,236	$ 9,025	$ (14,724)	$ 272,704
Current liabilities	$ 14,018	$ 36	$ 236	$ -	$ 14,290
Long-term liabilities					
Long-term debt	69,387	-	243	-	69,630
Asset retirement obligation	2,520	22	-	-	2,542
Total long-term liabilities	71,907	22	243	-	72,172
Minority interest	245	-	-	-	245
Shareholders' equity	185,997	6,178	8,546	(14,724)	185,997
Total liabilities and shareholders' equity	$272,167	$ 6,236	$ 9,025	$ (14,724)	$ 272,704

Condensed Consolidated Statement of Operations
Year Ended June 30, 2004

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 34,947	$ 1,429	$ 33	$ (33)	$ 36,376
Operating expenses:					
Lease operating expense	9,377	399	-	-	9,776
Depreciation and depletion	9,637	263	14	-	9,914
Exploration expense	2,405	-	1	-	2,406
Drilling and trucking operations	-	-	265	(33)	232
Dry hole, abandonment and impaired	2,132	-	-	-	2,132
General and administrative	7,906	19	124	-	8,049
Total expenses	31,457	681	404	(33)	32,509
Income (loss) from continuing operations	3,490	748	(371)	-	3,867
Other income and expenses	(1,643)	4	(1)	70	(1,570)
Discontinued operations	2,759	-	-	-	2,759
Net income (loss)	$ 4,606	$ 752	$ (372)	$ 70	$ 5,056

(12) Guarantee of Financial Information, Continued

Condensed Consolidated Statement of Cash Flows
Year Ended June 30, 2004

		Guarantor	Non-Guarantor	
	Issuer	Subsidiaries	Subsidiaries	Consolidated
Operating activities	$ 9,263	$ 518	$ (158)	$ 9,623
Investing activities	(144,232)	(370)	(3,836)	(148,438)
Financing activities	134,795	(218)	4,045	138,622
Net increase (decrease) in cash and cash equivalents	(174)	(70)	51	(193)
Cash at beginning of the period	2,160	110	1	2,271
Cash at the end of the period	$ 1,986	$ 40	$ 52	$ 2,078

Condensed Consolidated Statement of Operations
Year Ended June 30, 2003

	Guarantor	Non-Guarantor		
	Issuer	Subsidiaries	Subsidiaries	Consolidated
Total revenue	$ 19,119	$ 1,599	$ -	$ 20,718
Operating expenses:				
Lease operating expense	7,957	453	-	8,410
Depreciation and depletion	4,475	524		4,999
Exploration expense	140	-	-	140
Drilling and trucking operations	-	-	-	-
Dry hole, abandonment and impaired	530	7	-	537
General and administrative	4,987	21	129	5,137
Total expenses	18,089	1,005	129	19,223
Income (loss) from continuing operations	1,030	594	(129)	1,495
Other income and expenses	(1,770)	14	-	(1,756)
Discontinued operations	1,322	196	-	1,518
Net income (loss)	$ 582	$ 804	$ (129)	$ 1,257

(12) Guarantee of Financial Information, Continued

Condensed Consolidated Statement of Cash Flows
Year Ended June 30, 2003

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 7,042	$ 1,083	$ (126)	$ 7,999
Investing activities	(14,837)	82	107	(14,648)
Financing activities	8,992	(1,101)	5	7,896
Net increase (decrease) in cash and cash equivalents	1,197	64	(14)	1,247
Cash at beginning of the period	978	46	-	1,024
Cash at the end of the period	$ 2,175	$ 110	$ (14)	$ 2,271

(13) Commitments

The Company leases office space in Denver, Colorado and certain other locations in North America and also leases equipment and autos under non-cancelable operating leases. Rent expense, for the years ended June 30, 2005, 2004 and 2003 was approximately $491,000, $311,000 and $210,000, respectively. The following table summarizes the future minimum payments under all non-cancelable operating lease obligations:

	(In thousands)
2006	$ 1,998
2007	818
2008	825
2009	777
2010	765
2011 and thereafter	3,564
	$ 8,747

The Company has entered into agreements with three executive officers which provide for severance payments, two times the calculated average of the officer's combined annual salary and bonus, benefit continuation and accelerated vesting of options and stock grants in the event there is a change in control of the Company. The agreements expire no later than December 31, 2006, subject to automatic annual one-year renewals until cancelled by the Company.

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(14) Selected Quarterly Financial Data (Unaudited)

Fiscal 2005	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		(In thousands, except per share amounts)		
Total revenue	$ 19,338	$ 20,529	$ 26,566	$ 28,274
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	3,215	4,809	4,940	(1,688)
Net income	3,944	4,809	4,940	1,357
Net income per common share: (1)				
Basic	$ .10	$ .12	$ .12	$ .04
Diluted	$ .09	$ .11	$ .12	$ .04

Fiscal 2004	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
		(In thousands, except per share amounts)		
Total revenue	$ 6,755	$ 7,646	$ 10,308	$ 11,658
Income from continuing operations before income taxes, discontinued operations and cumulative effect	1,045	425	374	453
Net income	1,364	652	2,454	586
Net income per common share: (1)				
Basic	$ .06	$ .03	$ .09	$ .02
Diluted	$ .05	$ .03	$ .08	$ .02

(1) The sum of individual quarterly net income per share may not agree with year-to-date net income per share as each period's computation is based on the weighted average number of common shares outstanding during the period.

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(15) Disclosures About Capitalized Costs, Cost Incurred and Major Customers

Capitalized costs related to oil and gas activities are as follows:

	Years Ended June 30, 2005	2004
	(In thousands)	
Unproved offshore California properties	$ 10,925	$ 10,844
Unproved onshore domestic properties	91,010	38,903
Proved offshore California properties	12,207	9,103
Proved onshore domestic properties	353,099	214,042
	467,241	272,892
Accumulated depreciation and depletion	(43,034)	(21,317)
	$ 424,207	$ 251,575

Costs incurred[1] in oil and gas activities are as follows:

	Years Ended June 30, 2005		2004 (In thousands)		2003	
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Unproved property acquisition costs	$ 25,383	$ 81	$ 37,223	$ 680	$ 694	$ 442
Proved property acquisition costs	81,190	-	128,587	-	10,784	-
Developed cost incurred on undeveloped reserves	72,413	3,104	3,789	1,070	815	986
Development costs – other	36,369	-	20,986	-	4,335	-
Exploration costs	6,155	-	2,406	-	140	-
	$ 219,510	$ 3,185	$ 192,991	$ 1,750	$ 16,768	$ 1,428

(1) Included in costs incurred are asset retirement obligation costs incurred for all periods presented.

(15) Disclosures About Capitalized Costs, Cost Incurred and Major Customers, Continued

A summary of the results of operations for oil and gas producing activities, excluding general and administrative cost, is as follows:

	Years Ended June 30,					
	2005		2004 (In thousands)		2003	
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Revenue						
Oil and gas revenues	$ 85,680	$ 5,191	$ 33,251	$ 3,975	$ 17,987	$ 4,589
Expenses:						
Production costs	18,344	3,925	6,510	3,257	5,140	3,270
Depletion	20,171	720	8,978	705	3,860	1,075
Exploration	6,155	-	2,406	-	140	-
Abandonment and impaired Properties	-	-	-	-	-	-
Dry hole costs	2,771	-	2,132	-	537	-
Results of operations of oil and gas producing activities	$ 38,239	$ 546	$ 13,225	$ 13	$ 8,310	$ 244
Income (loss) from operations of properties sold, net	449	-	872	-	1,241	-
Gain (loss) on sale of properties	-	-	1,887	-	277	-
Cumulative effect on change in accounting and principle	-	-	-	-	(20)	-
Results of discontinued operations of oil and gas producing activities	$ 449	$ -	$ 2,759	$ -	$ 1,498	$ -

Statement of Financial Accounting Standards 131 "Disclosures about segments of an enterprise and Related Information" (SFAS 131) establishes standards for reporting information about operating segments in annual and interim financial statements. SFAS 131 also establishes standards for related disclosures about products and services, geographic areas and major customers. The Company's business segment includes its onshore and offshore properties described above and its drilling and trucking companies. The drilling and trucking companies had minimal activity. As such, segment information relating to the drilling and trucking companies has not been presented.

The Company's sales of oil and gas to individual customers which exceeded 10% of the Company's total oil and gas sales for the years ended June 30, 2005, 2004 and 2003 were:

	2005	2004	2003
Customer A	10%	17%	-%
Customer B	7%	17%	13%
Customer C	6%	10%	18%
Customer D	3%	14%	17%

(16) Information Regarding Proved Oil and Gas Reserves (Unaudited)

Proved Oil and Gas Reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. For the purposes of this disclosure, the Company has included reserves it is committed to and anticipates drilling.

(i) Reservoirs are considered proved if economic producability is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves;" (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids that may occur in underlaid prospects; and (D) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

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

Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other un-drilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

(16) Information Regarding Proved Oil and Gas Reserves (Unaudited), Continued

Estimates of our oil and natural gas reserves and present values for our fiscal years ended June 30, 2005, 2004 and 2003 are derived from reserve reports prepared by Ralph E. Davis Associates, Inc., our independent reserve engineers with respect to onshore reserves, or Mannon Associates, our independent reserve engineers with respect to offshore reserves.

A summary of changes in estimated quantities of proved reserves for the years ended June 30, 2005, 2004 and 2003 is as follows:

	Onshore		Offshore
	GAS (MMcf)	OIL (MBbl)	OIL (MBbl)
		(In thousands)	
Balance at June 30, 2002	43,953	3,919	902
Revisions of quantity estimate	13,719	(927)	244
Extensions and discoveries	687	-	1,132
Purchase of properties	236	1,024	-
Sale of properties	(457)	(66)	-
Production	(2,938)	(252)	(227)
Balance at June 30, 2003	55,200	3,698	2,051
Revisions of quantity estimate	(3,136)	469	(44)
Extensions and discoveries	6,560	69	-
Purchase of properties	39,782	8,306	-
Sale of properties	(6,817)	(596)	-
Production	(3,110)	(568)	(180)
Balance at June 30, 2004	88,479	11,378	1,827
Revisions of quantity estimate	(3,850)	(512)	(173)
Extensions and discoveries	39,459	1,162	-
Purchase of properties	32,282	1,397	-
Sale of properties	(7,654)	(153)	-
Production	(7,675)	(899)	(156)
Balance at June 30, 2005	141,041	12,373	1,493
Proved developed reserves:			
June 30, 2002	25,100	1,651	849
June 30, 2003	28,611	2,608	919
June 30, 2004	55,786	6,240	695
June 30, 2005	70,568	6,947	585

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
Notes to Consolidated Financial Statements
June 30, 2005, 2004 and 2003

(16) Information Regarding Proved Oil and Gas Reserves (Unaudited), Continued

Future net cash flows presented below are computed using year end prices and costs and are net of all overriding royalty revenue interests.

Future corporate overhead expenses and interest expense have not been included.

	Onshore	Offshore (In thousands)	Combined
June 30, 2005			
Future net cash flows	$ 1,724,986	$ 64,516	$ 1,789,502
Future costs:			
Production	366,453	19,286	385,739
Development and abandonment	183,416	8,934	192,350
Income taxes	294,754	-	294,754
Future net cash flows	880,363	36,296	916,659
10% discount factor	(387,874)	(11,415)	(399,289)
Standardized measure of discounted future net cash flows	$ 492,489	$ 24,881	$ 517,370
Standardized measure of discounted future net cash flows before tax	$ 658,848	$ 24,881	$ 683,729
Estimated future development cost anticipated for fiscal 2006 and 2007 on existing properties	$ 152,652	$ 6,004	$ 158,656
June 30, 2004			
Future net cash flows	$ 953,532	$ 51,625	$ 1,005,157
Future costs:			
Production	225,046	23,558	248,604
Development and abandonment	55,845	11,054	66,899
Income taxes	165,492	-	165,492
Future net cash flows	507,149	17,013	524,162
10% discount factor	230,540	5,585	236,125
Standardized measure of discounted future net cash flows	$ 276,609	$ 11,428	$ 288,037
Standardized measure of discounted future net cash flows before tax	$ 367,679	$ 11,428	$ 379,107
June 30, 2003			
Future cash flows	$ 377,458	$ 46,898	$ 424,356
Future costs:			
Production	99,243	24,787	124,030
Development and abandonment	20,104	13,137	33,241
Income taxes	62,390	-	62,390
Future net cash flows	195,721	8,974	204,695
10% discount factor	93,734	3,750	97,484
Standardized measure of discounted future net cash flows	$ 101,987	$ 5,224	$ 107,211
Standardized measure of discounted future net cash flows before tax	$ 134,667	$ 5,224	$ 139,891

(16) Information Regarding Proved Oil and Gas Reserves (Unaudited), Continued

The principal sources of changes in the standardized measure of discounted net cash flows during the years ended June 30, 2005, 2004 and 2003 are as follows:

	2005	2004 (In thousands)	2003
Beginning of the year	$ 288,037	$ 107,211	$ 62,384
Sales of oil and gas production during the period, net of production costs	(68,602)	(27,459)	(16,082)
Purchase of reserves in place	201,693	248,478	14,335
Net change in prices and production costs	90,938	26,088	37,957
Changes in estimated future development costs	19,345	8,592	(8,251)
Extensions, discoveries and improved recovery	93,624	11,599	3,032
Revisions of previous quantity estimates, estimated timing of development and other	(91,002)	(25,807)	25,675
Previously estimated development and abandonment costs incurred during the period	72,413	4,859	1,801
Sales of reserves in place	(42,508)	(17,934)	(1,122)
Change in future income tax	(75,371)	(58,311)	(18,756)
Accretion of discount	28,803	10,721	6,238
End of year	$ 517,370	$ 288,037	$ 107,211

(17) Subsequent Events

On September 9, 2005, the Company completed the sale of its interest in the Deerlick Field located in Tuscaloosa, Alabama, for cash consideration of $30.0 million and an effective date of July 1, 2005. The Company expects to record a tax deferred gain on the sale of oil and gas properties of approximately $18.0 million. Revenues from these oil and gas properties were approximately $4.9 million, $3.3 million and $3.0 million for the years ended June 30, 2005, 2004 and 2003, respectively.

On September 7, 2005 the Company entered into an agreement to purchase an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington, and to purchase an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant Resources, LLC ("Savant") for an aggregate purchase price of $85 million, on or before September 30, 2005. James Wallace, a director of Delta, owns approximately a 1.7% interest in Savant, and also serves as a director of Savant. The majority of the acquired acreage in the Columbia River Basin consolidates the Company's current leasehold position, whereby subsequent to the acquisition Delta will own a 100% working interest in approximately 310,000 net acres. This acquisition also includes a small portion of acreage that is subject to an agreement with EnCana Oil & Gas (USA) Inc., whereby the Company will have the right to convert an overriding royalty interest to a working interest at project payout. In the Piceance Basin, the Company is acquiring Savant's interest in an entity that owns a 25% interest in approximately 6,314 gross acres that is currently being developed.

GLOSSARY OF OIL AND GAS TERMS

The terms defined in this section are used throughout this Annual Report.

Bbl. Barrel (of oil or natural gas liquids).

Bcf. Billion cubic feet (of natural gas).

Bcfe. Billion cubic feet equivalent.

Bbtu. One billion British Thermal Units.

Developed acreage. The number of acres which are allocated or held by producing wells or wells capable of production.

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

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

Equivalent volumes. Equivalent volumes are computed with oil and natural gas liquid quantities converted to Mcf on an energy equivalent ratio of one barrel to six Mcf.

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

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

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

Liquids. Describes oil, condensate, and natural gas liquids.

MBbls. Thousands of barrels.

Mcf. Thousand cubic feet (of natural gas).

Mcfe. Thousand cubic feet equivalent.

MMBtu. One million British Thermal Units, a common energy measurement.

MMcf. Million cubic feet.

MMcfe. Million cubic feet equivalent.

NGL. Natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells expressed in whole numbers.

NYMEX. New York Mercantile Exchange.

Present value or PV10% or "SEC PV10%." When used with respect to oil and gas reserves, present value or PV10% or SEC PV10% means the estimated future gross revenue to be generated from the production of net proved reserves, net of estimated production and future development and abandonment 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, accretion, and future income tax expense or to depreciation, depletion, and amortization, discounted using monthly end-of-period discounting at a nominal discount rate of 10% per annum.

Productive wells. Producing wells and wells that are capable of production, including injection wells, salt water disposal wells, service wells, and wells that are shut-in.

Proved developed reserves. Estimated proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Estimated proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required.

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

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

REPORT ON FORM 10-K

A Copy of Delta's Annual Report on Form 10-K for the fiscal year ended June 30, 2005, will be provided to holders of the Company's securities at no charge on request by contacting the Company at 303-293-9133 or by writing to 370 17th Street, Suite 4300, Denver, CO 80202.

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Roger A. Parker
President, CEO, Chairman

Kevin K. Nanke
Treasurer, CFO

John R. Wallace
Executive Vice President, COO

Kevin R. Collins
Director

Jerrie F. Eckelberger
Director

Aleron H. Larson, Jr.
Director

Russell S. Lewis
Director

Jordan R. Smith
Director

Neal A. Stanley
Director

James P. Van Blarcom
Director

James B. Wallace
Director

Stock Listing
NASDAQ
Symbol - DPTR

Independent Auditors
KPMG LLP
Denver, Colorado

Transfer Agent
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Denver, Colorado 80209
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Communications concerning the transfer of shares, lost certificates, duplicate mailings or change of address should be directed to the transfer agent

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The annual meeting of Stockholders of Delta Petroleum Corporation will be held at 10:00 a.m. on January 31, 2006 at the Brown Palace Hotel, 321 17th Street, Denver CO 80202.

Cover photo
Steven Adams, Photographer
DHS Drilling Rig #1, Diamond State 36-13 in the Howard Ranch Development Project, WY.

DELTA
PETROLEUM CORPORATION

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