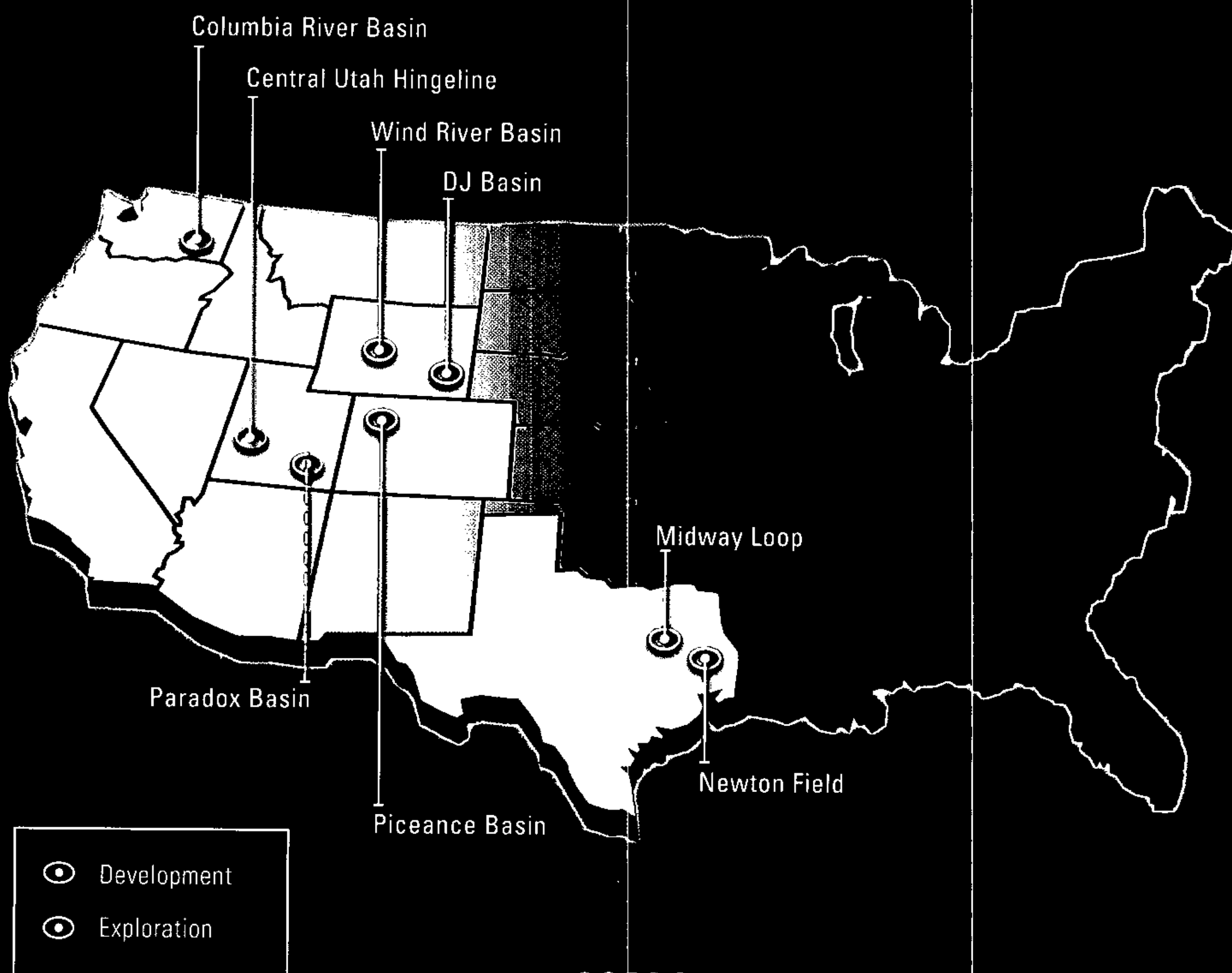
DELTA PETROLEUM CORPORATION

2007 ANNUAL REPORT

OPERATING AREAS



CORPORATE PROFILE

Delta Petroleum Corporation is an independent oil and gas 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 onshore Gulf Coast Regions, which together comprise the majority of our proved reserves, production and long-term growth prospects. We have a significant development drilling inventory that consists of proved and unproved locations, the majority of which are located in our Rocky Mountain development projects.

FINANCIAL RESULTS

(In thousands except per share amounts)

Years Ended December 31	2007	2006	(Unaudited) 2005
Total Revenue	$ 164,190	$ 146,660	$ 84,818
Operating Expenses	$ 295,531	$ 163,998	$ 91,825
Operating Loss	$ (131,341)	$ (17,338)	$ (7,007)
Other Expense	$ (28,887)	$ (16,235)	$ (28,526)
Income (Loss) from Continuing Operations	$ (160,228)	$ (33,623)	$ (35,533)
Income Tax (Expense) Benefit	$ (2,677)	$ 12,623	$ 17,485
Loss from Continuing Operations	$ (162,905)	$ (21,000)	$ (18,048)
Discontinued Operations and Extraordinary Gain	$ 13,558	$ 21,435	$ 23,754
Net Income (Loss)	$ (149,347)	$ 435	$ 5,706
Net Income (Loss) Per Share-Basic	$ (2.44)	$ 0.01	$ 0.13
Net Income (Loss) Per Share-Diluted	$ (2.44)	$ 0.01	$ 0.13
Current Assets	$ 133,069	$ 89,794	$ 61,589
Net Property and Equipment	$ 930,027	$ 815,200	$ 621,154
Total Long Term Assets	$ 42,099	$ 24,329	$ 10,650
Total Assets	$ 1,105,195	$ 929,323	$ 693,393
Current Liabilities	$ 143,196	$ 99,579	$ 106,772
Long-Term Debt	$ 426,298	$ 374,121	$ 241,659
Other Liabilities	$ 27,296	$ 27,390	$ 24,507
Stockholders' Equity	$ 508,405	$ 428,233	$ 320,455
Total Liabilities and Stockholders' Equity	$ 1,105,195	$ 929,323	$ 693,393

OIL & GAS RESERVES AND OPERATIONS

Years Ended December 31

	2007	2006	2005
Proved Reserves			
Oil, Condensate and NGL's (MBbls)	11,025	12,947	14,709
Natural Gas (MMcf)	309,473	224,704	181,154
Natural Gas Equivalents (MMcfe)	375,626	302,386	269,408
Percent Developed	32%	34%	39%
SEC PV-10 After Tax (000)	$ 701,874	$ 483,234	$ 749,624
Finding Cost ($/Mcfe, drill bit)	$ 2.41	$ 3.04	$ NA[1]
Finding Cost ($/Mcfe, all inclusive)	$ 2.80	$ 3.58	$ NA[1]
Annual Production			
Oil, Condensate and NGL's (MBbls)	1,085	1,354	1,058
Natural Gas (MMcf)	11,253	8,022	8,098
Natural Gas Equivalents (MMcfe)	17,763	16,146	14,446
Reserve/Production Ratio (Years)	21.2	18.7	18.6
Production Replacement %	700%	473%	NA[1]

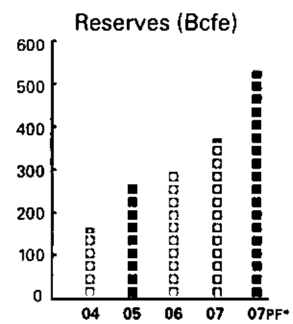
(1) Not available due to change in fiscal year during 2005

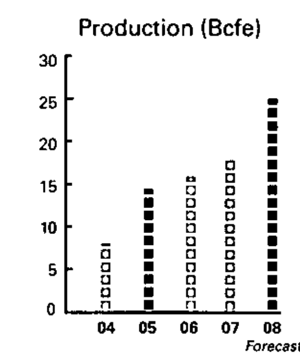
DEAR SHAREHOLDERS

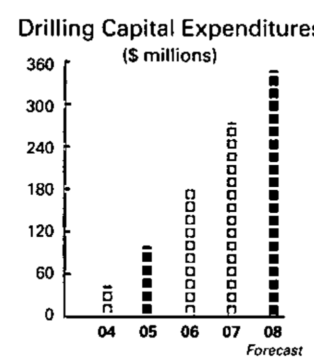
The year 2007 was a period of meaningful operational successes for Delta Petroleum. Our accomplishments included record production, a substantial increase in proved reserves, and other operational improvements that we believe position the Company for continued gains in the years to come. More recently, during the first quarter of 2008, we closed two key transactions that will allow Delta to achieve even stronger industry-leading growth.

In February 2008, we closed on the sale of 36 million shares of common stock to Tracinda Corporation, which now owns 35% of Delta. Tracinda's investment provided $684 million in new capital that will be used to accelerate our drilling programs, particularly in the Piceance and Paradox Basins in the Rocky Mountain region. With the closing of this transaction, Tracinda has named two members to our Board of Directors and has the right to name up to three additional directors. We believe our partnership with Tracinda will provide Delta with the ability to substantially grow the Company and further enhance shareholder value. We welcome Tracinda as a major shareholder and look forward to its role as a partner in Delta's future accomplishments.

In 2007, our production increased 10% when compared with the previous year. If production from assets that were sold during 2007 is included, our growth would have approximated 23% in 2007. We expanded our proved reserves by 24% to 376 billion cubic feet equivalents (Bcfe), of which 77% are located in the Rocky Mountain region. Revenue increased 12% to $164.2 million, compared with $146.7 million in 2006. While we







* 2007 Proved Reserves
Pro forma for Piceance Transaction

reported a net loss of $149.3 million, or $2.44 per share, in 2007, EBITDAX increased 9% to a record $83.0 million, compared with $76.4 million in 2006, and discretionary cash flow increased 24% to $75.0 million, versus $60.5 million in 2006. The net loss was primarily attributed to dry hole costs, an impairment totaling $85.1 million and a $49.6 million valuation allowance required to be recorded against the Company's deferred tax assets. Consistent with the growth in production and reserves, we hired an additional 23 employees during the year, and we are confident we have the technical team in place to execute the Company's development plans. We believe that our operational accomplishments during 2007, particularly in the Piceance and Paradox Basins, will translate to improved financial performance in 2008 and beyond.

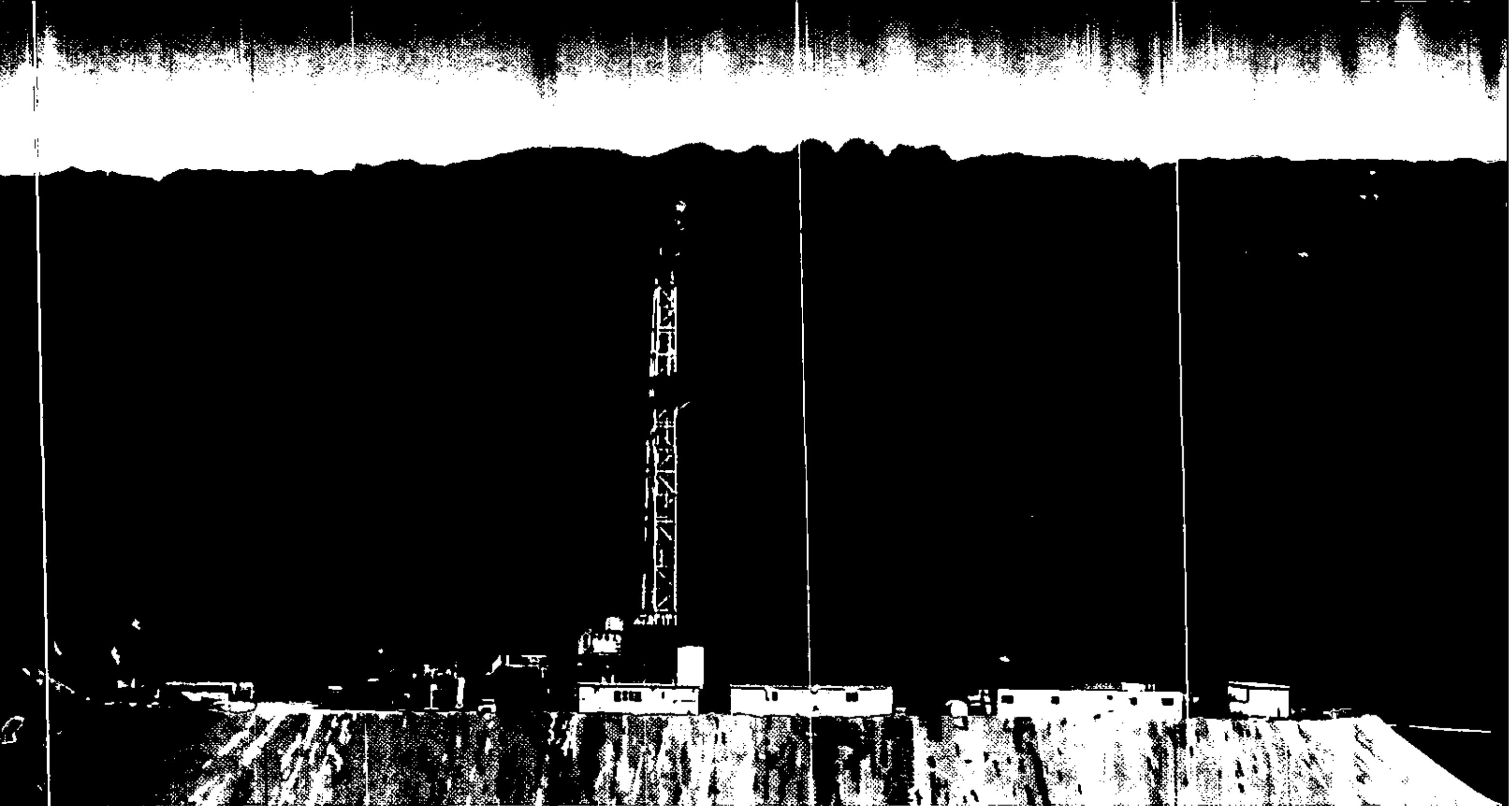
In February 2008, we closed on a transaction that provides Delta with a contiguous block of over 18,000 net acres adjacent to our Vega Unit. The transaction significantly increases our 2007 year-end estimated total Company proved reserves on a pro forma basis to 530 Bcfe and provides Delta an additional 1,700 drilling locations. Our exposure to more than 2,000 well locations on over 30,000 net acres in the Piceance Basin represents an impressive 10-year drilling inventory for the Company.

As discussed in last year's annual report, we completed a very meaningful discovery at our Greentown prospect in the Paradox Basin at the end of 2006. An emerging core area, the Greentown project is located in Grand County, Utah, where we have accumulated a 70% working interest in 46,000 acres. Delta has now drilled four exploratory wells, each of which has encountered significant reserve potential. The project is currently being developed with two drilling rigs, with the expectation that activity will increase during 2008. Delta is currently constructing a 25 mile natural gas pipeline and processing plant that should be completed during the second quarter of 2008, with production sales to commence thereafter. Drilling capital expenditures for this area should approximate $40 million in 2008.

Our exposure to more than 2,000 well locations in the Piceance Basin represents an impressive 10-year drilling inventory for the Company.

We continue to focus on the development of our low-risk, repeatable drilling inventory in the Piceance Basin, where production increased from 5 million cubic feet per day (MMcf/d) at the beginning of 2007 to approximately 40 MMcf/d by year-end. Proved reserves in the Piceance Basin increased 90% to 182.5 Bcfe during the year. We also significantly improved our operational results in the Vega Area, driven by lower well costs. The wells that we are currently drilling in the Vega Area are costing 40% less than comparable wells drilled in 2006. The Vega Area is our single largest producing field and should be the primary contributor to our production growth in 2008. We are currently devoting four drilling rigs full time to our Vega leasehold and anticipate an increase to eight rigs by early 2009. We have budgeted 2008 capital expenditures of $250 to $260 million for the Piceance Basin.

In the Central Utah Hingeline Region, where we have an average 65% working interest in 180,000 acres, we have drilled two exploratory wells. Our most recent well, the Federal 23-44, will begin production testing in the third quarter of 2008 when raptor nesting restrictions have been lifted. We plan to drill a third well during 2008 and have budgeted $7 to $8 million in drilling capital expenditures for the year.



We believe that our operational accomplishments during 2007, particularly in the Piceance and Paradox Basins, will translate to improved financial performance in 2008 and beyond.

During the current year, we anticipate drilling our first well on our leasehold of 508,000 net acres in the Columbia River Basin in southeast Washington and northeast Oregon. The Gray 31-23 will be our first operated well in the basin and is projected to spud during the second quarter. We look forward to testing the large resource potential of the Columbia River Basin.

We expect 2008 to be an exciting year for Delta and its shareholders, with Company-wide production expected to increase 45% to 60% from 2007 levels, which represents superior production growth within the industry. We anticipate spending $350 to $370 million in drilling capital expenditures.

In closing, we would like to express our gratitude for the continued support we have received from our shareholders and the Board of Directors. Our employees have demonstrated the loyalty, skills and determination necessary to build Delta into a premier oil and gas company, and we are very appreciative of their efforts. We believe 2008 will represent another year of significant accomplishments at Delta Petroleum Corporation as we strive to enhance the Company's value for all stakeholders.

Sincerely,

Roger A. Parker
Chairman and Chief Executive Officer

John R. Wallace
President and Chief Operating Officer

DESCRIPTION OF BUSINESS

General

Delta Petroleum Corporation is an independent oil and gas 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 onshore Gulf Coast Regions, which together comprise the majority of our proved reserves, production and long-term growth prospects. We have a significant development drilling inventory that consists of proved and unproved locations, the majority of which are located in our Rocky Mountain development projects.

We generally 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. We also have an ownership interest in a drilling company, providing the benefit of priority access to 15 drilling rigs that operate primarily in the Rocky Mountain Region.

Delta was incorporated in Colorado in 1984. Effective January 31, 2006, Delta reincorporated in Delaware, thereby changing our state of incorporation from Colorado to Delaware. Our principal executive offices are located at 370 17th Street, Suite 4300, Denver, Colorado 80202. Our telephone number is (303) 293-9133. We also maintain a website at http://www.deltapetro.com which contains information about us. Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports are accessible free of charge at our website.

Overview and Strategy

Our focus is to increase stockholder value by pursuing our corporate strategy, as follows:

Pursue concurrent development of our core areas

We plan to spend $350.0-$370.0 million on our drilling program during 2008. We expect that approximately 88% of the 2008 drilling capital expenditures will be incurred in our Rocky Mountain development and exploration projects. Many of our targeted development drilling locations are in reservoirs that demonstrate predictable geologic attributes and consistent reservoir characteristics, which typically lead to reliable drilling results.

Achieve consistent reserve growth through repeatable development

We have experienced significant reserve growth over the past four years through a combination of acquisitions and drilling successes. Although prior to 2006 the majority of our reserve and production growth came through acquisitions, in 2007 we achieved significant reserve and production increases as a result of our drilling program. We anticipate that the majority of our 2008 and future reserve and production growth will come through the execution of our drilling program on our large inventory of proved and unproved locations. Our development drilling inventory generally consists of locations in fields that demonstrate low variance in well performance, which leads to predictable and repeatable field development.

Our reserve estimates change continuously and we evaluate such reserve estimates on a quarterly basis, with independent engineering evaluation on an annual basis. Deviations in the market prices of both crude oil and natural gas and the effects of acquisitions, dispositions and exploratory development activities may have a significant effect on the quantities and future values of our reserves. Our reserves in the Rocky Mountain Region, where we plan to increasingly focus our drilling efforts and capital expenditures, are generally characterized as long-lived with low decline rates. We believe the balance of high-return Gulf Coast drilling and long-lived Rockies reserves will allow us to increase near term production rates and cash flow while building our reserve base and lengthening our average reserve life, which was 21.2 years as of December 31, 2007, based on 2007 production.

Maintain high percentage ownership and operational control over our asset base

As of December 31, 2007, we controlled approximately 871,000 net undeveloped acres, representing approximately 98% of our total net acreage position. We retain a high degree of operational control over our asset base, through a high average working interest or acting as the operator in our areas of significant activity. 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 plan to maintain this advantage to allow us to control the timing, level and allocation of our drilling capital expenditures and the technology and methods utilized in the planning, drilling and completion process. We believe this flexibility to opportunistically pursue exploration and development projects relating to our properties provides us with a meaningful competitive advantage. We also have a 50.0% interest in DHS Drilling Company ("DHS"), as well as a contractual right of priority access to DHS'15 drilling rigs, which are deployed primarily in the Rocky Mountains.

Acquire and maintain acreage positions in high potential resource plays

We believe that our ongoing development of reserves in our core areas should be supplemented with exploratory efforts that may lead to new discoveries in the future. We continually evaluate our opportunities and pursue attractive potential opportunities that take advantage of our strengths. At December 31, 2007, we had significant undeveloped, unproved acreage positions in both the Columbia River Basin and the Central Utah Hingeline plays, each of which has gained substantial interest within the exploration and production sector due to their relatively unexplored nature and the potential for meaningful hydrocarbon recoveries. There are other mid-size and large independent exploration and production companies conducting drilling activities in these plays. We anticipate that meaningful drilling and completion results will become known in both areas during 2008.

Pursue a disciplined acquisition strategy in our core areas of operation

Historically we have been successful at growing through targeted acquisitions. Although our multi-year drilling inventory provides us with the opportunity to grow reserves and production organically without acquisitions, we continue to evaluate acquisition opportunities, primarily in our core areas of operation. In addition, we will continue to look to divest assets located in fully developed or non-core areas.

Maintain an active hedging program

We manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. We use hedges to limit the risk of fluctuating cash flows used to fund our capital expenditure program. We also typically use hedges in conjunction with acquisitions to achieve expected economic returns during the payout period. As of February 26, 2008 approximately 12.2 Bcfe of our anticipated production is hedged for 2008.

Experienced management and operational team with advanced exploration and development technology

Our senior management team has over 25 years of experience in the oil and gas industry, and has a proven track record of creating value both organically and through strategic acquisitions. Our management team is supported by an active board of directors with extensive experience in the oil and gas industry. Our experienced technical staff utilizes sophisticated geologic and 3-D seismic models to enhance predictability and reproducibility over significantly larger areas than historically possible. We also utilize multi-zone, multi-stage artificial stimulation ("frac") technology in completing our wells to substantially increase near-term production, resulting in faster payback periods and higher rates of return and present values. Our team has successfully applied these techniques, normally associated with completions in the most advanced Rocky Mountain natural gas fields, to our largest Gulf Coast field to improve initial and ultimate production and returns.

Operations

During the year ended December 31, 2007, we were primarily engaged in two industry segments, namely the acquisition, exploration, development, and production of oil and natural gas properties and related business activities, and contract oil and natural gas drilling operations.

Oil and Gas Operations

The following table presents information regarding our primary oil and natural gas areas of operation as of December 31, 2007:

Areas of Operations	Proved Reserves (Bcfe) (1)	% Natural Gas	% Proved Developed	2007 Production (MMcfe/d) (2)
Rocky Mountain Region	288.8	90.3%	25.8%	19.3
Gulf Coast Region	80.6	58.4%	49.7%	23.6
Offshore California	2.0	-%	100.0%	2.4
Other	4.2	37.9%	72.7%	3.4
Total	375.6	82.4%	31.8%	48.7

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

We intend to focus our development on two of our primary areas of operation, the Rocky Mountain and onshore Gulf Coast Regions. For the year ending December 31, 2008, we estimate that our drilling capital budget will range between \$350.0 - \$370.0 million.

Our oil and gas operations have been comprised primarily of production of oil and natural gas, drilling exploratory and development wells and related operations and acquiring and selling oil and natural gas properties. Directly or through wholly-owned subsidiaries, and through Amber Resources Company of Colorado ("Amber"), our 91.68% owned subsidiary, CRB Partners, LLC ("CRBP") and PGR Partners, LLC ("PGR"), we currently own producing and non-producing oil and natural 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 Colorado, Utah, Texas and Wyoming.

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 debtor in any bankruptcy, receivership, reorganization or similar proceeding.

Contract Drilling Operations

Through a series of transactions in 2004 and 2005, we acquired and now own an interest in DHS, an affiliated Colorado corporation that is headquartered in Casper, Wyoming. During the second quarter of 2006, DHS engaged in a reorganization transaction pursuant to which it became a subsidiary of DHS Holding Company, a Delaware corporation, and the Company's ownership interest became an interest in DHS Holding Company. References to DHS herein shall be deemed to include both DHS Holding Company and DHS, unless the context otherwise requires. DHS is a consolidated entity of Delta. Delta currently owns a 50.0% interest in DHS Holding Company, controls the board of directors of DHS and has priority access to all of DHS' drilling rigs for Company use and operations.

At December 31, 2007, DHS owned 15 drilling rigs with depth ratings of approximately 10,000 to 20,000 feet. We have the right to use all of the rigs on a priority basis, although approximately half are currently working for third party operators.

The following table presents our average drilling revenue per day and rigs available for service for the years ended December 31, 2007 and 2006:

	Years Ended December 31,	
	2007	2006
Average number of rigs owned during period	16.7	12.3
Total rig days available[1]	5,020	4,482
Average drilling revenue per day	$ 16,919	$ 16,747

[1]Total rig days available includes the number of days each rig was either under contract or available for contract.

DHS also owns 100% of Chapman Trucking, which was acquired in November 2005. Employing its 28 trucks and 38 trailers, Chapman ensures DHS rig mobility and provides moving services for third party drilling rigs. Chapman Trucking continues to market trucking services in the Casper, Wyoming area.

DIRECTORS AND EXECUTIVE OFFICERS

Our executive officers and members of our Board of Directors, and their respective ages, are as follows:

Name	Age	Positions	Period of Service
Roger A. Parker	46	Chairman, Chief Executive Officer and a Director	May 1987 to Present
John R. Wallace	48	President, Chief Operating Officer and a Director	October 2003 to Present
Kevin K. Nanke	43	Treasurer and Chief Financial Officer	December 1999 to Present
Stanley F. Freedman	59	Executive Vice President, General Counsel and Secretary	January 2006 to Present
Hank Brown	68	Director	June 2007 to Present
Kevin R. Collins	51	Director	March 2005 to Present
Jerrie F. Eckelberger	63	Director	September 1996 to Present
Aleron H. Larson, Jr.	62	Director	May 1987 to Present
Russell S. Lewis	53	Director	June 2002 to Present
James J. Murren	46	Director	February 2008 to Present
Jordan R. Smith	73	Director	October 2004 to Present
Neal A. Stanley	60	Director	October 2004 to Present
Daniel J. Taylor	51	Director	February 2008 to Present
James B. Wallace	78	Director	November 2001 to Present

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

Roger A. Parker has been a Director since May 1987 and Chief Executive Officer since April 2002. He served as our President from May 1987 until February 2006 when he resigned to accommodate the appointment of John R. Wallace to that position. He was named Chairman of the Board on July 1, 2005. Since April 1, 2005, he has also served as Executive Vice President and Director of DHS. 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 board member of the Independent Petroleum Association of the Mountain States (IPAMS). He also serves on other boards, including Community Banks of Colorado.

John R. Wallace, President and Chief Operating Officer, joined Delta in October 2003 as Executive Vice President of Operations and was appointed President in February 2006 and a Director in June 2007. Since April 1, 2005, he has also served as Executive Vice President and Director of DHS. Mr. Wallace was Vice President of Exploration and Acquisitions for United States Exploration, Inc. ("UXP"), a Denver-based publicly-held oil and gas exploration company, from May 1998 to October 2003. Prior to UXP, Mr. Wallace served as president of various privately held oil and gas companies engaged in producing property acquisitions and exploration ventures. He received a Bachelor of Science in Geology from Montana State University in 1981. He is a member of the American Association of Petroleum Geologists and the Independent Petroleum Association of the Mountain States. Mr. Wallace is the son of James B. Wallace, a Director of the Company.

Kevin K. Nanke, Treasurer and Chief Financial Officer, joined Delta in April 1995 as our Controller and has served as the Treasurer and Chief Financial Officer of Delta and Amber Resources since 1999. Since April 1, 2005 he has also served as Chief Financial Officer, Treasurer and Director of DHS. 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.

Stanley F. ("Ted") Freedman has served as Executive Vice President, General Counsel and Secretary since January 1, 2006 and has also served in those same capacities for DHS since that same date. He also serves as Executive Vice President and Secretary of Amber Resources. He graduated from the University of Wyoming with a Bachelor of Arts degree in 1970 and a Juris Doctor degree in 1975. From 1975 to 1978, Mr. Freedman was a staff attorney with the United States Securities and Exchange Commission. From 1978 to December 31, 2005, he was engaged in the private practice of law, and was a shareholder and director of the law firm of Krys Boyle, P.C. in Denver, Colorado.

Hank Brown currently serves as President Emeritus of the University of Colorado and holder of the Quigg and Virginia S. Newton Endowed Chair in Leadership. From June 2005 to March 2008 he served as the President of the University of Colorado. Prior to joining CU in June 2005 he was President and CEO of the Daniels Fund and served as the President of the University of Northern Colorado from 1998 to 2002. He served Colorado in the United States Senate (elected in 1990) and served five consecutive terms in the U.S. House representing Colorado's 4th Congressional District (1980-1988). He also served in the Colorado Senate from 1972 to 1976. Mr. Brown was a Vice President of Monfort of Colorado from 1969 to 1980. He is both an attorney and a C.P.A. He earned a Bachelor's degree in Accounting from the University of Colorado in 1961 and received his Juris Doctorate degree from the University of Colorado Law School in 1969. While in Washington, D.C., Mr. Brown earned a Master of Law degree in 1986 from George Washington University. Mr. Brown also currently serves as a director of Sensient Technologies Corporation and Sealed Air Corporation, both of which are publicly held.

Kevin R. Collins currently serves as President, Chief Executive Officer and a Director of Evergreen Energy Inc., which is listed on the New York Stock Exchange Arca. Prior to his current position, Mr. Collins served as Evergreen's Executive Vice President and Chief Operation Officer from September 2005 to April 2007, and acting Chief Financial Officer from November 2005 until March 31, 2006. Mr. Collins also serves as a director of Quest Midstream Partners, L.P. From 1995 until 2004, Mr. Collins was an executive officer of Evergreen Resources, Inc. (NYSE), serving as Executive Vice President and Chief Financial Officer until Evergreen Resources merged with Pioneer Natural Resources Co. in September 2004. Mr. Collins became a Certified Public Accountant in 1983 and has over 13 years' 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, and board member and Chairman of the Finance Committee of the Independent Petroleum Association of Mountain States. Mr. Collins received his Bachelor of Science 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 the present, Mr. Eckelberger has been engaged in the private practice of law in the Denver area. 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 Resources, 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. He ceased to be an officer or director of Amber Resources on January 3, 2006. 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 has served as Senior Vice President of Strategic Development at Verisign (Nasdaq: VRSN) since July 2007, where his is responsible for rationalizing the company's lines of businesses. He also serves as 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 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 TransCore, a wireless transportation systems integration company that was and still is the market leader in electronic toll collection systems. Prior to that, Mr. Lewis managed an oil and gas exploration subsidiary of UGI, a publicly traded gas utility and was Vice President of EF Hutton in its Municipal Finance group. Mr. Lewis also serves on the Boards of Braintech, a publicly traded company that is a leader in vision guided robotics and NameMedia, a private backed firm that holds a significant portfolio of internet domain names. Mr. Lewis has a BA degree in Economics from Haverford College and an MBA from the Harvard School of Business.

James J. Murren is the President and Chief Operating Officer of MGM Mirage. He is also a member of the Board of Directors and the Executive Committee. Mr. Murren has also served as the Chief Financial Officer of MGM Mirage from January 1998 to August 2007 and Treasurer of MGM Mirage from November 2001 to August 2007. Prior to MGM Mirage, Mr. Murren spent 14 years on Wall Street as a top-ranked equity analyst and was appointed to Director or Research and Managing Director of Deutsche Bank. Mr. Murren received a Bachelors of Arts degree in Art History and Urban Studies from Trinity College in 1983.

Jordan R. Smith is President of Ramshorn Investments, Inc., a wholly owned subsidiary of Nabors Drilling USA LP that is located in Houston, Texas, 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 and sole shareholder since 1991. From 1996 to June 2003, he was Senior Vice President – Western Region for Forest Oil Corporation, Denver, Colorado. Since December 2005, Mr. Stanley has served as a member of the Board of Directors and Compensation Committee for Calgary based Pure Energy Services Ltd., which is listed on the Toronto Stock Exchange under the symbol PSV. 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.

Daniel J. Taylor is an executive employed by Tracinda Corporation and currently serves as a Director of MGM Mirage. Mr. Taylor previously was the President of Metro-Goldwyn-Mayer Inc. ("MGM Studios") from April 2005 to January 2006 and Senior Executive Vice President and Chief Financial Officer of MGM Studios from June 1998 to April 2005.

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 formerly served as a member of the Board of Directors of Ellora Energy, Inc., a public oil and gas exploration company listed on the NASDAQ. 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 President, Chief Operating Officer and a Director of Delta.

MARKET FOR COMMON STOCK AND RELATED STOCKHOLDER MATTERS

Delta's common stock currently trades under the symbol "DPTR" on the NASDAQ Global 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, 2005	$20.82	$14.01
December 31, 2005	22.31	15.07
March 31, 2006	$24.95	$17.82
June 30, 2006	22.71	13.79
September 30, 2006	23.27	15.02
December 31, 2006	30.68	20.81
March 31, 2007	$23.12	$17.57
June 30, 2007	24.94	18.62
September 30, 2007	20.35	14.40
December 31, 2007	21.58	13.06

On February 28, 2008, the closing price of our common stock was $24.86. We have not paid dividends on our common stock, and we do not expect to do so in the foreseeable future. Our current debt agreements restrict the payment of dividends.

STOCK PERFORMANCE GRAPH

The performance graph shown below was prepared using data prepared by CTA Integrated Communications. As required by applicable rules of the SEC, the graph was prepared based upon the following assumptions:

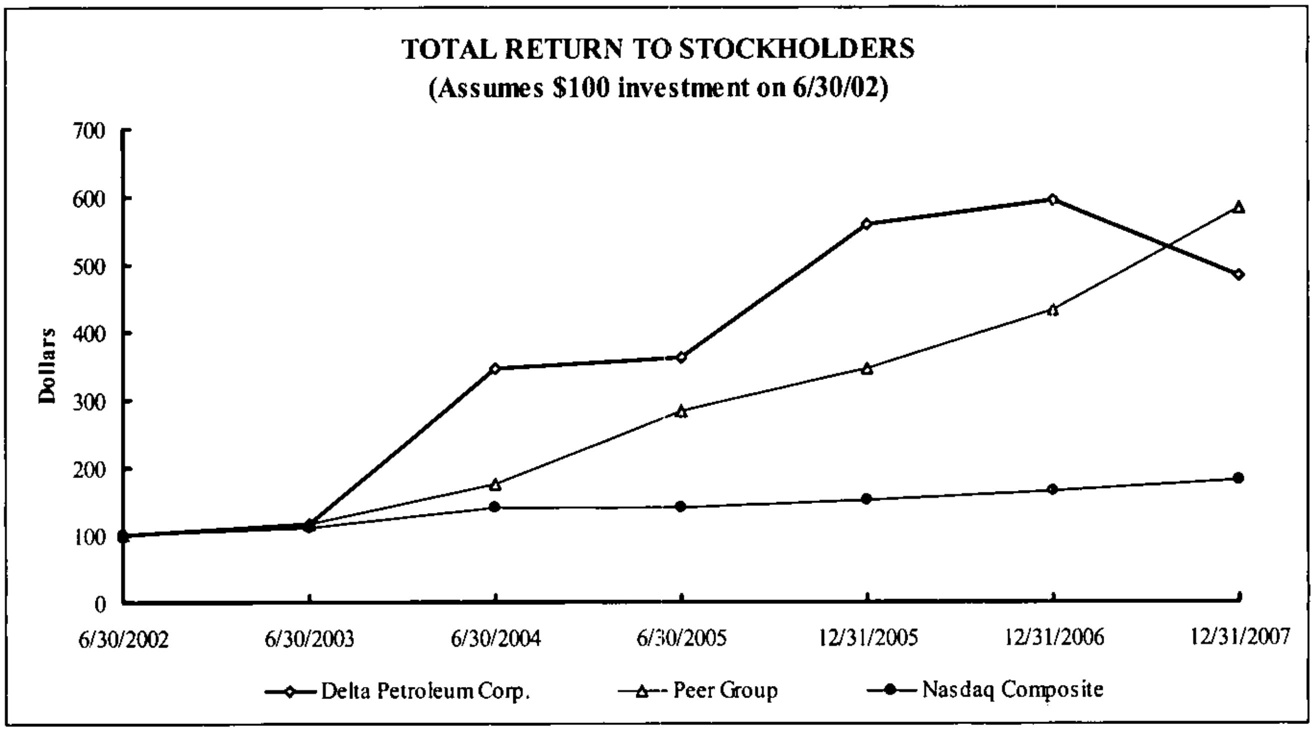
1. $100 was invested in Common Stock, the Nasdaq Composite Index (U.S.) and the Peer Group (as defined below) on June 30, 2002.

2. The Peer Group investment is weighted based on the market capitalization of each individual company within the Peer Group at the beginning of each period.

3. Dividends are reinvested on the ex-dividend dates.

The companies that comprise the Peer Group are: Range Resources Corporation; St Mary Land & Exploration Co.; Edge Petroleum Corp.; Plains Exploration & Production Co.; Brigham Exploration Co.; Forest Oil Corp.; Whiting Petroleum Corp.; and Cimarex Energy Co.

COMPARATIVE CUMULATIVE TOTAL RETURNS
DELTA PETROLEUM CORPORATION
NASDAQ COMPOSITE INDEX AND PEER GROUP
(Performance results through December 31, 2007)



Total Return Analysis	6/30/2002	6/30/2003	6/30/2004	6/30/2005	12/31/2005	12/31/2006	12/31/2007
Delta Petroleum Corp.	$100.00	$117.44	$344.87	$362.05	$558.21	$593.85	$483.33
Peer Group	$100.00	$115.29	$174.48	$283.24	$345.40	$431.91	$584.36
Nasdaq Composite	$100.00	$110.91	$139.95	$140.58	$150.72	$165.07	$181.26

SELECTED FINANCIAL DATA

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

	Years Ended December 31,		Six Months Ended December 31,	Years Ended June 30,		
	2007	2006	2005	2005	2004	2003
	(In thousands, except per share amounts)					
Total Revenues	$ 164,190	$ 146,660	$ 48,326	$ 56,612	$ 9,799	$ 5,551
Income (loss) from Continuing Operations	$ (160,228)	$ (33,623)	$ (29,203)	$ (10,353)	$ (12,081)	$ (8,156)
Net Income (Loss)	$ (149,347)	$ 435	$ (590)	$ 15,050	$ 5,056	$ 1,257
Income/(Loss) Per Common Share						
Basic	$ (2.44)	$ .01	$ (.01)	$ .37	$ .19	$ .05
Diluted	$ (2.44)	$ .01	$ (.01)	$ .36	$ .17	$ .05
Total Assets	$ 1,105,195	$ 929,323	$ 693,393	$ 512,983	$ 272,704	$ 86,847
Total Liabilities	$ 569,494	$ 473,700	$ 357,442	$ 276,746	$ 86,462	$ 38,944
Minority Interest	$ 27,296	$ 27,390	$ 15,496	$ 14,614	$ 245	$ -
Stockholders' Equity	$ 508,405	$ 428,233	$ 320,455	$ 221,623	$ 185,997	$ 47,903
Total Long-Term Liabilities	$ 426,298	$ 374,121	$ 257,743	$ 222,596	$ 72,172	$ 33,082

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

Overview

We are a Denver, Colorado based independent oil and gas 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. At December 31, 2007, we had estimated proved reserves that totaled 375.6 Bcfe, of which 31.8% were proved developed, with an after-tax PV-10 value of $701.9 million. As of December 31, 2007, we achieved net production of 48.7 Mmcfe per day and net continuing production of 37.5 Mmcfe per day.

As of December 31, 2007, our reserves were comprised of approximately 309.5 Bcf of natural gas and 11.0 Mmbbls of crude oil, or 82.4% gas on an equivalent basis. Approximately 21% of our proved reserves were located in the Gulf Coast, 77% in the Rocky Mountains, and 2% in other locations. We expect that our drilling efforts and capital expenditures will focus increasingly on the Rockies, where approximately 87-89% of our fiscal 2008 drilling budget is allocated and more than one-half of our undeveloped acreage is located. As of December 31, 2007, we controlled approximately 871,000 net undeveloped acres, representing approximately 98% of our total acreage position. We retain a high degree of operational control over our asset base, with an average working interest in excess of 85% (excluding CRB properties) as of December 31, 2007. 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 have a controlling ownership interest in a drilling company, providing the benefit of access to 15 drilling rigs primarily located in the Rocky Mountain Region. 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.

We expect our 2008 oil and gas production to increase 45% to 60% due to the expected results of our budgeted drilling program. For calendar year 2008, we have preliminarily established a drilling budget of approximately $350.0 to $370.0 million. We are concentrating a substantial portion of this budget on the development of our Paradox, Piceance and Wind River Basin assets in the Rockies, and to a lesser extent, our Newton and Midway Loop fields in the Gulf Coast. State of the art geologic and seismic geophysical modeling indicates that these fields have targeted geologic formations containing substantial hydrocarbon deposits that can be economically developed. Recently completed successful wells in several of our Rocky Mountain development programs have found multiple accumulations of tight sand reservoirs at various depths, characterized by low permeability and high pressure. These types of reservoirs possess predictable geologic attributes and consistent reservoir characteristics which typically result in a higher drilling success rate and lower per well cost and risk.

The exploration for and the acquisition, development, production, and sale of, natural gas and crude oil are highly competitive and capital intensive. As in any commodity business, the market price of the commodity produced and the costs associated with finding, acquiring, extracting, and financing the operation are critical to profitability and long-term value creation for stockholders. Generating reserve and production growth represents an ongoing focus for management, and is made particularly important in our business by the natural production and reserve decline associated with oil and gas properties. In addition to developing new reserves, we compete to acquire additional reserves, which involves judgments regarding recoverable reserves, future oil and gas prices, operating costs and potential environmental and other liabilities, title issues and other factors. During periods of historically high oil and gas prices, third party contractor and material cost increases are more prevalent due to increased competition for goods and services. Other challenges we face include attracting and retaining qualified personnel, gaining access to equipment and supplies and maintaining access to capital on sufficiently favorable terms.

We have taken the following steps to mitigate the challenges we face. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, typically costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our review of market conditions, available hedge prices and our operating strategy. As of February 26, 2008, our derivative contracts cover approximately 12.2 Bcfe of our estimated 2008 oil and gas production. Our interest in a drilling and trucking company allows us to mitigate the increasing challenge for rig availability in the

Rocky Mountains and also helps to control third party contractor and material costs. Our business strengths include a multi-year inventory of attractive drilling locations and a diverse balance of high return Gulf Coast properties and long lived Rockies reserves, which we believe will allow us to grow reserves and replace and expand production organically without having to rely solely on acquisitions.

Recent developments

During the year ended December 31, 2007, we achieved the following:

- Increased proved reserves to 375.6 Bcfe at December 31, 2007, an increase of 24.2%, or 31.2% after considering current year sales and purchases, compared to proved reserves as of December 31, 2006 of 302.4 Bcfe.

- Our total production for the year ended December 31, 2007 was 17.8 Bcfe. Adjusted for asset dispositions, our production from continuing operations increased 19% to 13.7 Bcfe, compared to 11.6 Bcfe for the prior year period, primarily as a result of successful exploratory and development drilling during 2007.

Results of Operations

The following discussion and analysis relates to items that have affected our results of operations for the years ended December 31, 2007, 2006 and 2005, six months ended December 31, 2005 and 2004, and the fiscal year ended June 30, 2005. During 2005, we changed our fiscal year end from June 30 to December 31, effective December 31, 2005. Accordingly, we have presented below for comparative purposes unaudited historical statements of operations for the year ended December 31, 2005 and six months ended December 31, 2004. The following table sets forth (in thousands), for the periods presented, selected historical statements of operations data. The information contained in the table below should be read in conjunction with our consolidated financial statements and accompanying notes included in this Annual Report.

	Years Ended December 31,			Six Months Ended December 31,		Year Ended June 30,
	2007	2006	2005 (Unaudited)	2005	2004 (Unaudited)	2005
Revenue:						
Oil and gas sales	$ 94,559	$ 94,223	$ 75,176	$ 42,643	$ 19,913	$ 52,446
Contract drilling and trucking fees	56,777	57,149	13,592	9,096	300	4,796
Gain (loss) on effective derivative instruments, net	12,854	(4,712)	(3,950)	(3,413)	(93)	(630)
Total Revenue	164,190	146,660	84,818	48,326	20,120	56,612
Operating Expenses:						
Lease operating expense	20,142	17,655	12,606	6,507	3,193	9,291
Transportation expense	3,684	978	994	680	81	394
Production taxes	5,559	4,784	4,307	2,455	1,563	3,415
Depreciation, depletion and amortization – oil and gas	63,373	53,980	21,594	12,411	4,862	14,055
Depreciation and amortization – drilling and trucking	22,052	16,404	3,987	2,847	386	1,525
Exploration expense	9,062	4,690	6,933	2,061	1,283	6,155
Dry hole costs and impairments	85,084	15,682	5,521	5,423	2,673	2,771
Drilling and trucking operations	36,954	34,163	9,413	5,821	1,074	4,666
General and administrative	49,621	35,696	26,470	16,491	6,951	16,930
Gain on sale of oil and gas properties	-	(20,034)	-	-	-	-
Total operating expenses	295,531	163,998	91,825	54,696	22,066	59,202
Operating loss	(131,341)	(17,338)	(7,007)	(6,370)	(1,946)	(2,590)
Other income and (expense):						
Other income (expense)	376	(154)	(427)	(36)	(179)	(570)
Gain on sale of marketable securities	-	-	1,194	1,194	-	-
Gain on sale of investment in LNG	-	1,058	-	-	-	-
Gain (loss) on ineffective derivative instruments, net	(2,902)	11,722	(14,767)	(14,437)	-	(330)
Minority interest	1,231	(2,595)	14	(688)	315	1,017
Losses from unconsolidated affiliates	(393)	-	-	-	-	-
Interest and financing costs	(27,199)	(26,316)	(14,540)	(8,866)	(2,206)	(7,880)
Total other expense	(28,887)	(16,285)	(28,526)	(22,833)	(2,070)	(7,763)
Loss from continuing operations before income taxes and discontinued operations	(160,228)	(33,623)	(35,533)	(29,203)	(4,016)	(10,353)
Income tax benefit (expense)	(2,677)	12,623	17,485	10,873	-	11,969
Net income (loss) from continuing operations	(162,905)	(21,000)	(18,048)	(18,330)	(4,016)	1,616
Income from discontinued operations of properties sold, net of tax	17,556	9,163	11,966	5,952	12,770	13,434
Gain (loss) on sale of oil and gas properties, net of tax	(3,998)	6,712	11,788	11,788	-	-
Extraordinary gain, net of tax	-	5,560	-	-	-	-
Net income (loss)	$(149,347)	$ 435	$ 5,706	$ (590)	$ 8,754	$ 15,050

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Net Income (Loss). Net loss was $149.3 million, or $2.44 per diluted common share, for the year ended December 31, 2007, compared to net income of $435,000 or $.01 per diluted common share, for the year ended December 31, 2006. Loss from continuing operations increased from $21.0 million for the year ended December 31, 2006 to a loss of $162.9 million for the year ended December 31, 2007, due primarily to dry hole costs and impairments, first half 2006 gains on undeveloped property sales and gains on ineffective derivative instruments that did not occur during 2007, and due to higher depreciation, depletion, and amortization expense, and increased general and administrative expense in 2007. Net loss increased significantly due to the valuation allowance required to be recorded against the Company's deferred tax assets during the second quarter of 2007.

Oil and Gas Sales. During the year ended December 31, 2007, oil and gas sales from continuing operations were $94.6 million, as compared to $94.2 million for the comparable period a year earlier. During the year ended December 31, 2007, production from continuing operations increased by 19%; however, this was offset by a 23% decrease in the average gas price. The average onshore gas price received during the year ended December 31, 2007 was $4.47 per Mcf compared to $5.79 per Mcf for the year earlier period, primarily due to the increase in the basis differential applicable to Rocky Mountain natural gas. The average onshore oil price received during the year ended December 31, 2007 increased to $68.85 per Bbl compared to $64.37 per Bbl for the year earlier period and the offshore oil price increased to $52.96 per Bbl during the year ended December 31, 2007 compared to $46.75 for the year earlier period.

Net gains (losses) from effective hedging activities were a $12.9 million gain and a $4.7 million loss for the years ended December 31, 2007 and 2006, respectively. The gain in 2007 realized hedges is primarily due to lower oil and gas prices. These gains (losses) are recorded as an increase or decrease in revenues.

Contract Drilling and Trucking Fees. At December 31, 2007 DHS owned 15 drilling rigs with depth ratings of approximately 10,000 to 20,000 feet. We have the right to use all of the rigs on a priority basis, although approximately half are currently working for third party operators.

Drilling revenues for the year ended December 31, 2007 remained flat at $50.5 million compared to $50.0 million for the prior year period. Drilling revenue is earned under daywork or turnkey contracts where we provide a drilling rig with required personnel to our third party customers who supervise the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is in use or on a negotiated fixed rate for drilling to a certain depth. During the mobilization period we typically earn a fixed amount of revenue based on the mobilization rate set in the contract. Drilling revenues earned on wells drilled for Delta have been eliminated through consolidation.

Trucking revenues for the year ended December 31, 2007 were $6.3 million compared to $7.1 million for the prior year period. Trucking revenues decreased in 2007 due to fewer rigs being transported in Wyoming where C&L Drilling operates.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the years ended December 31, 2007 and 2006 are as follows:

	Years Ended December 31,			
	2007		2006[1]	
	Onshore	Offshore	Onshore	Offshore
Production – Continuing Operations:				
Oil (MBbl)	703	146	856	162
Gas (MMcf)	8,600	-	5,438	-
Production – Discontinued Operations:				
Oil (MBbl)	236	-	335	-
Gas (MMcf)	2,652	-	2,585	-
Total Production (MMcfe)	16,888	875	15,173	975
Average Price – Continuing Operations:				
Oil (per barrel)	$ 68.85	$ 52.96	$ 64.37	$ 46.75
Gas (per Mcf)	$ 4.47	$ -	$ 5.79	$ -
Costs per Mcfe – Continuing Operations:				
Hedge gain (loss)	$ 1.00	$ -	$ (.45)	$ -
Lease operating expense	$ 1.29	$ 4.09	$ 1.32	$ 3.75
Production taxes	$ .43	$ .07	$ .45	$ .05
Transportation costs	$ .29	$ -	$ .09	$ -
Depletion expense	$ 4.69	$ 1.47	$ 4.85	$ 1.08

[1] Revised for operations discontinued in 2007.

Lease Operating Expense. Lease operating expenses for the year ended December 31, 2007 were $20.1 million compared to $17.7 million for the year earlier period. Lease operating expense from continuing operations for onshore properties for the year ended December 31, 2007 was $1.29 per Mcfe as compared to $1.32 per Mcfe for the year earlier period.

Depreciation, Depletion and Amortization – oil and gas. Depreciation, depletion and amortization expense increased 17% to $63.4 million for the year ended December 31, 2007, as compared to $54.0 million for the year earlier period. Depletion expense for the year ended December 31, 2007 was $61.5 million compared to $52.4 million for the year ended December 31, 2006. The 17% increase in depletion expense was due to a 19% increase in production from continuing operations, slightly offset by a 3% decrease in the onshore depletion rate. Our onshore depletion rate decreased to $4.69 per Mcfe for the year ended December 31, 2007 from $4.85 per Mcfe for the year earlier period. The decrease is partially due to lower finding costs per Mcfe on the Company's extensive 2007 Rockies drilling program. Based on impairments recorded in 2007 and the Company's continued focus in the Rockies which continues to result in better well economics, the Company anticipates its depletion rate will continue to decrease in 2008.

Depreciation and Amortization – drilling and trucking. Depreciation and amortization expense – drilling and trucking increased to $22.1 million for the year ended December 31, 2007 as compared to $16.4 million for the prior year period. This increase can be attributed to a greater average number of rigs that DHS owned in 2007 compared to the prior year.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended December 31, 2007 were $9.1 million compared to $4.7 million for the year earlier period. Current year exploration activities increased and included the acquisition and processing of the seismic program related to acreage in Opossum Hollow, Texas, processing for 2D seismic costs in the central Utah Hingeline, and 3D seismic costs to evaluate leasehold positions for additional drilling locations in Wyoming.

Dry Hole Costs and Impairments. We incurred dry hole costs of approximately $26.7 million for the year ended December 31, 2007 compared to $4.3 million for the comparable period a year ago. For the year ended December 31, 2007, our dry hole costs related primarily to seven exploratory projects, three in Texas, two in Wyoming, one well in Colorado and one in Utah. For the year ended December 31, 2006, the dry hole costs related primarily to exploratory projects in Texas and Utah.

During the year ended December 31, 2007, the Company recorded impairments totaling approximately $58.4 million primarily related to the Howard Ranch and Fuller fields in Wyoming ($37.5 million and $10.3 million, respectively), and the South Angleton field in Texas ($9.7 million), primarily due to lower Rocky Mountain natural gas prices and marginally economic deep zones on the Howard Ranch Prospect.

During the year ended December 31, 2006, an impairment of $10.4 million was recorded on certain of the Company's eastern Colorado properties primarily due to lower Rocky Mountain natural gas prices. In addition, an impairment of $1.0 million was recorded on certain Oklahoma properties that are held for sale at December 31, 2007.

Drilling and Trucking Operations. We had drilling and trucking operations expense of $37.0 million during the year ended December 31, 2007 compared to $34.2 million during the year ended December 31, 2006. The significant increase in expenses was due to the greater average overall number of rigs in operation for DHS in 2007 than in the prior year.

General and Administrative Expense. General and administrative expense increased 39% to $49.6 million for the year ended December 31, 2007, as compared to $35.7 million for the comparable prior year period. The increase in general and administrative expenses is primarily attributed to an increase in non-cash equity compensation of $10.7 million and a 23% increase in technical and administrative staff and related personnel costs.

Gain on Sale of Oil and Gas Properties. In January and March 2006, Delta sold a combined 44% minority interest in CRBP. As the sale involved unproved properties, no gain on the partial sale of CRBP could be recognized until all of the cost basis of CRBP had been recovered. Accordingly, we recorded a $13.0 million gain ($8.1 million net of tax), and an $11.2 million reduction to property during the first quarter of 2006 as a result of closing the transaction. In November 2006, we sold certain undeveloped property interests in the Columbia River Basin for proceeds of $2.0 million. We recorded a gain on the transaction of $1.1 million.

In March 2006, we sold approximately 26% of PGR. This transaction involved both proved and unproved property interests and accordingly, to the extent the sale of PGR related to unproved properties, no gain could be recognized as all of the unproved cost basis was not yet recovered. We recorded a gain of $5.9 million, $3.7 million net of tax, and a $3.4 million offset to property during the first quarter of 2006 as a result of the transaction. We retained a 74% interest in, and are the manager of, PGR.

Gain on Sale of Investment in LNG Project. On March 30, 2006, we sold our long-term minority interest investment in an LNG project for total proceeds of $2.1 million. We recorded a gain on sale of $1.1 million ($657,000 net of tax).

Gain (Loss) on Ineffective Derivative Instruments, Net. Effective July 1, 2007, we discontinued cash flow hedge accounting. Beginning July 1, 2007, we recognize mark-to-market gains and losses in current earnings instead of deferring those amounts in accumulated other comprehensive income for the contracts that qualify as cash flow hedges. As a result, we recognized in our statements of operations a loss of $2.9 million for the year ended December 31, 2007 and a gain of $11.7 million for the year ended December 31, 2006.

Minority Interest. Minority interest represents the minority investors' percentage of their share of income or losses from DHS in which they hold an interest. During the year ended December 31, 2007 DHS generated a loss resulting in decreased minority interest expense.

Interest and Financing Costs, Net. Interest and financing costs increased 3% to $27.2 million for the year ended December 31, 2007, as compared to $26.3 million for the comparable year earlier period. The increase is primarily related to higher average debt balances on DHS' credit facility during the year and costs related to the refinancing of DHS credit facilities in May and December, offset by lower average balances outstanding on Delta's credit facility.

Income Tax Expense. Due to our continued losses, we were required by the "more likely than not" provisions of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"), to record a valuation allowance on our deferred tax assets beginning with the second quarter of 2007. As a result, our income tax expense for the year ended December 31, 2007 of $2.7 million includes a valuation allowance of $57.4 million. During the year ended December 31, 2006, an income tax benefit of $12.6 million was recorded for continuing operations at an effective tax rate of 37.5%.

Discontinued Operations. Discontinued operations include the Frisco field in Pointe Coupee Parish, Louisiana, which was sold in June 2006, the Panola and Rusk County, Texas properties, which were sold in August 2006, the East Texas and Pennsylvania properties, which were sold in August 2006, the Kansas field, which was sold in January 2007, the Australia field and the New Mexico and East Texas properties, which were sold in March 2007, the North Dakota properties sold in September 2007, the Washington County, Colorado properties sold in October 2007, and the Midway Loop, Texas properties held for sale at December 31, 2007. The results of operations on these assets, net of tax, during the years ended December 31, 2007 and 2006 were $17.6 million and $9.2 million, respectively. The significant increase in 2007 was primarily due to new wells in 2007 from the Company's Midway Loop drilling program or wells drilled in 2006 impacting sales for the full year in 2007.

Gain (Loss) on Sale of Discontinued Operations. During the year ended December 31, 2007, we sold non-core properties in Colorado, Kansas, Texas, New Mexico, Australia and North Dakota for combined proceeds of $46.4 million and a combined net loss of $4.0 million. During the year ended December 31, 2006, we sold certain non-core properties located in Louisiana and East Texas for combined proceeds of $23.8 million and an after-tax gain of $6.7 million.

Extraordinary Gain. On August 21, 2006, the Company completed the sale of the properties acquired with the Castle acquisition in April 2006. During the year ended December 31, 2006 the Company recorded a $5.6 million extraordinary gain, net of tax in accordance with SFAS No. 141 "Business Combinations" ("SFAS 141").

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005 (Unaudited)

Net Income. Net income decreased $5.3 million to $435,000, or $.01 per diluted common share, for the year ended December 31, 2006, as compared to net income of $5.7 million, or $.13 per diluted common share, for the year ended December 31, 2005. This decrease was primarily due to an $10.3 million increase in operating losses resulting from higher revenue and a $20.0 million gain on the sale of oil and gas properties, offset by higher depreciation, depletion, and amortization expense, higher exploration, dry hole and abandonment costs, and increased general and administrative expenses.

Oil and Gas Sales. During the year ended December 31, 2006, oil and natural gas revenue from continuing operations increased 25% to $94.2 million, as compared to $75.2 million for the year ended December 31, 2005. The increase was the result of a 19% increase in average daily production from continuing operations over the year ended December 31, 2005, an increase in average onshore oil price received in the year ended December 31, 2006 of $64.37 per Bbl compared to $54.77 per Bbl during the same period in 2005, and an increase in offshore oil price received of $46.75 per Bbl during the year ended December 31, 2006 compared to $41.46 during the year ended December 31, 2005, partially offset by a decrease in the average onshore gas price received during the year ended December 31, 2006 of $5.79 per Mcf compared to $7.09 per Mcf received in the year ended December 31, 2005.

Net realized losses from effective hedging activities were $4.7 million and $4.0 million for the years ended December 31, 2006 and 2005, respectively. The increase in 2006 in realized hedging losses is primarily due to higher oil prices. These losses are recorded as a decrease in total revenues.

Contract Drilling and Trucking Fees. At December 31, 2006 DHS owned 16 drilling rigs with depth ratings of approximately 7,500 to 20,000 feet. We have the right to use all of the rigs on a priority basis, although approximately three-fourths were working for third party operators at December 31, 2006.

Drilling revenues for the year ended December 31, 2006 increased to $50.0 million compared to $13.0 million for the prior year period. Drilling revenue is earned under daywork contracts where we provide a drilling rig with required personnel to our third party customers who supervise the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is in use. During the mobilization period we typically earn a fixed amount of revenue based on the mobilization rate set in the contract. Drilling revenues earned on wells drilled for Delta have been eliminated through consolidation. At December 31, 2006 there were 16 DHS rigs in operation compared to eight rigs in operation at December 31, 2005.

Trucking revenues for the year ended December 31, 2006 were $7.1 million compared to $630,000 for the prior year period. Trucking revenues were insignificant during the year ended December 31, 2005 as the acquisition of Chapman Trucking Company was completed in November, 2005.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the years ended December 31, 2006 and 2005 are as follows:

	Year Ended December 31,			
	2006[1]		2005[1]	
	Onshore	Offshore	Onshore	Offshore
Production – Continuing Operations:				
Oil (MBbl)	856	162	508	162
Gas (MMcf)	5,438	-	5,727	-
Production – Discontinued Operations:				
Oil (MBbl)	335	-	387	-
Gas (MMcf)	2,585	-	2,371	-
Total Production (MMcfe)	15,173	975	13,474	972
Average Price – Continuing Operations:				
Oil (per barrel)	$ 64.37	$ 46.75	$ 54.77	$ 41.46
Gas (per Mcf)	$ 5.79	$ -	$ 7.09	$ -
Costs per Mcfe – Continuing Operations:				
Hedge gain (loss)	$ (.45)	$ -	$ (.45)	$ -
Lease operating expense	$ 1.32	$ 3.75	$ .95	$ 4.42
Production taxes	$ .45	$ .05	$ .48	$ .06
Transportation costs	$ .09	$ -	$ .11	$ -
Depletion expense	$ 4.85	$ 1.08	$ 2.27	$ .79

[1] Revised for operations discontinued in 2007.

Lease Operating Expense. Lease operating expenses for the year ended December 31, 2006 were $17.7 million compared to $12.6 million for the same period a year earlier. Lease operating expense increased due to our 19% increase in production and due to increased per unit costs. Lease operating expense from continuing operations for onshore properties for the year ended December 31, 2006 was $1.32 per Mcfe as compared to $.95 per Mcfe for the same period a year earlier. Lease operating expense from continuing operations for offshore properties was $3.75 per Mcfe for the year ended December 31, 2006 and $4.42 per Mcfe for the same period a year earlier. The increase in onshore per unit lease operating expenses is a result of generally rising field costs due to increased demand for services, and is also affected by overall infrastructure costs for some properties that were still experiencing limited production due to pipeline constraints.

Depreciation, Depletion and Amortization – oil and gas. Depreciation, depletion and amortization expense increased 130% to $54.0 million in the year ended December 31, 2006, as compared to $21.6 million for the year ended December 31, 2005. Depletion expenses for our onshore properties increased to $4.85 per Mcfe during the year ended December 31, 2006 from $2.27 per Mcfe for the year ended December 31, 2005. The depletion rate increase is partially due to certain deep, multi-stage completion projects in which the majority of our well costs are depleted over completed zones that have not met initial expectations. Also, during the year ended December 31, 2006, a $3.0 million developmental dry hole in South Angleton was added to the depletion pool.

Depreciation and Amortization – drilling and trucking. Depreciation and amortization expense – drilling and trucking increased to $16.4 million for the year ended December 31, 2006 as compared to $4.0 million for the prior year period. This increase can be attributed to additional rigs acquired by DHS Drilling Company.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the year ended December 31, 2006 were $4.7 million compared to $6.9 million for the year ended December 31, 2005. Activities in the year ended December 31, 2006 included activities in our Columbia River Basin, Washington, Grand County, Utah and Newton County, Texas projects. During the year ended December 31, 2005, our most significant exploration cost was related to the $1.4 million Newton 3D seismic shoot covering 58 square miles which was completed and processed during 2005. In addition, we acquired 2D data in the Gulf Coast Region and also began acquiring geophysical data on the Columbia River Basin properties in the state of Washington.

Dry Hole Costs and Impairments. We incurred dry hole costs of approximately $4.3 million for the year ended December 31, 2006 compared to $4.2 million for the same period in the prior year. During 2005, a significant portion of these costs were related to dry holes that were drilled in Utah and California. For the year ended December 31, 2006, the dry hole costs related primarily to exploratory projects in Texas and Utah.

During the year ended December 31, 2006, an impairment of $10.4 million was recorded on certain of the Company's eastern Colorado properties primarily due to lower Rocky Mountain natural gas prices. In addition, an impairment of $1.0 million was recorded on certain Oklahoma properties that were held for sale at December 31, 2006. During 2007, we are continuing to develop and evaluate certain properties on which favorable or unfavorable results or commodity prices may cause us to revise in future quarters our estimates of those properties' future cash flows. Such revisions of estimates could require us to record an impairment in the period of such revisions.

During the year ended December 31, 2005, a dry hole was drilled on a prospect located in California. Based on drilling results and evaluation of the prospect, we determined that we would not pursue development and accordingly an impairment of $1.3 million was recorded for the full impairment of the remaining leasehold costs related to the prospect.

Drilling and Trucking Operations. We had drilling and trucking operations expense of $34.2 million during the year ended December 31, 2006 compared to $9.4 million during the year ended December 31, 2005. The significant increase in expenses was due to an increase in the number of rigs in operation, 16 rigs as of December 31, 2006 compared to eight rigs at December 31, 2005.

General and Administrative Expense. General and administrative expense increased 35% to $35.7 million for the year ended December 31, 2006 as compared to $26.5 million for the year ended December 31, 2005. The increase in general and administrative expenses is primarily attributed to an increase in non-cash equity compensation of $2.1 million, a 45% increase in technical and administrative staff and related personnel costs, and the expansion of our office facility. In addition, $2.1 million of the increase is related to DHS general and administrative expense. DHS general and administrative expense increased with added headcount for DHS growth during the year ended December 31, 2006 and a full year of operations in 2006 compared to nine months of operations in 2005.

Gain on Sale of Oil and Gas Properties. During December 2005, Delta transferred its ownership in approximately 427,000 gross acres (64,000 net acres) of non-operated interests in the Columbia River Basin to CRBP. In January and March 2006, Delta sold a combined 44% minority interest in CRBP. Accordingly, the Company recorded a $13.0 million gain ($8.1 million, net of tax) and a $11.2 million reduction to property during the first quarter of 2006 as a result of the closing of the transaction.

In November 2006, the Company sold certain undeveloped property interests in the Columbia River Basin for proceeds of $2.0 million. The Company recorded a gain on the transaction of $1.1 million.

In March 2006, the Company sold approximately 26% of PGR. This transaction involved both proved and unproved property interests and accordingly, to the extent the sale of PGR related to unproved properties, no gain could be recognized as all of the unproved cost basis was not yet recovered. The Company recorded a gain of $5.9 million, $3.7 million net of tax, and a $3.4 million offset to property during the first quarter of 2006 as a result of the transaction. The Company retained a 74% interest in, and is the manager of, PGR.

Gain on Sale of Marketable Security. During the year ended December 31, 2005, the Company sold investment securities classified as available-for-sale securities resulting in a realized gain of $1.2 million.

Gain on Sale of Investment in LNG Project. On March 30, 2006, the Company sold its long-term minority interest investment in an LNG project for total proceeds of $2.1 million. The Company recorded a gain on sale of $1.1 million ($657,000 net of tax).

Gain (Loss) on Ineffective Derivative Instruments, Net. During the year ended December 31, 2005, our gas derivative contracts became ineffective and no longer qualified for hedge accounting. Hedge ineffectiveness results from different changes in the NYMEX contract terms and the physical location, grade and quality of our oil and gas production. The change in fair value of our NYMEX gas contracts is reflected in earnings, as opposed to being recorded in other comprehensive income (loss), a component of stockholders' equity. As a result, we recognized an $11.7 million gain and a $14.8 million loss in our statements of operations for the years ended December 31, 2006 and 2005, respectively. As commodity prices fluctuate, we will record our NYMEX gas derivative contracts at market value with any changes in market value recorded through unrealized gain (loss) on derivative contracts in our statement of operations.

Minority Interest. Minority interest represents the minority investors' percentage of their share of income or losses from DHS in which they hold an interest. During the year ended December 31, 2006 DHS generated a greater profit, resulting in increased minority interest expense.

Interest and Financing Costs. Interest and financing costs increased 81% to $26.3 million for the year ended December 31, 2006, as compared to $14.5 million for the year ended December 31, 2005. The increase is primarily related to the increase in the average amount outstanding under our credit facility, higher interest rates and the increased long term debt balance related to the DHS credit facility. In addition, during 2006, DHS incurred a pre-payment penalty of $820,000 and wrote-off deferred financing costs of $431,000 to pay-off a term loan that was replaced with a lower interest rate term loan.

Income tax benefit. During the year ended December 31, 2006, an income tax benefit of $12.6 million was recorded for continuing operations at an effective tax rate of 37.5% compared to an income tax benefit of $17.5 million and an effective tax rate of 49.2% for the year ended December 31, 2005. The 2005 rate was significantly affected by the reversal of a valuation allowance related to the Company's deferred tax assets.

Discontinued Operations. Discontinued operations include the Deerlick Creek Field in Tuscaloosa County, Alabama, which was sold in September 2005, the Frisco Field in Pointe Coupee Parish, Louisiana, which was sold in June 2006, the Panola and Rusk County, Texas properties, which were sold in August 2006, the East Texas and Pennsylvania properties, which were sold in August 2006, and the Kansas Field, which was sold in January 2007, the Australia field and the New Mexico and East Texas properties, which were sold in March 2007, the North Dakota properties sold in September 2007, the Washington County, Colorado properties sold in October 2007, and the Midway Loop, Texas properties held for sale at December 31, 2007. The results of operations on these assets, net of tax, during the years ended December 31, 2006 and 2005 were $9.2 million and $12.0 million, respectively.

Extraordinary Gain. An extraordinary gain was recorded during the year ended December 31, 2006 as required by SFAS 141. Due to the excess fair value of the assets compared to the purchase price of the transaction and the Company's intention to sell the oil and gas properties, Delta recorded a $5.6 million extraordinary gain, net of tax, during the year ended December 31, 2006. The oil and gas properties acquired from Castle were in fact sold during August 2006.

Six Months Ended December 31, 2005 Compared to Six Months Ended December 31, 2004 (Unaudited)

Net Income. Net income decreased $9.5 million to a net loss of $590,000 or $.01 per diluted common share for the six months ended December 31, 2005, as compared to net income of $8.8 million or $.21 per diluted common share for the six months ended December 31, 2004. This decrease was primarily due to a $14.4 million loss for ineffective hedges, $3.4 million of realized losses on effective hedging contracts, higher exploration and dry hole costs, increased general and administrative expenses of $9.5 million due to the growth in the Company's operations and activities, and increased interest and financing costs of $6.7 million due to higher average debt outstanding.

Revenue. During the six months ended December 31, 2005, oil and natural gas revenue from continuing operations increased 114% to $42.6 million, as compared to $19.9 million for the six months ended December 31, 2004. The increase was the result of an average onshore gas price received during the six months ended December 31, 2005 of

$8.78 per Mcf compared to $5.56 per Mcf received in the six months ended December 31, 2004, an increase in average onshore oil price received in the six months ended December 31, 2005 of $59.62 per Bbl compared to $45.41 per Bbl during the same period in 2004, an increase in offshore oil price received of $47.12 per Bbl during the six months ended December 31, 2005 compared to $30.66 during the six months ended December 31, 2004, and a 44% increase in continuing average daily production over the six months ended December 31, 2004.

Cash payments required on our effective hedging activities impacted revenues during the six months ended December 31, 2005 and 2004. The cost of settling our effective hedging activities was $3.4 million and $93,000 during the six months ended December 31, 2005 and 2004, respectively.

Contract Drilling and Trucking Fees. At December 31, 2005 DHS owned eleven drilling rigs with depth ratings of approximately 7,500 to 20,000 feet. In early 2006, two additional rigs were acquired. We have the right to use all of the rigs on a priority basis, although approximately half were working for third party operators at December 31, 2005.

Drilling revenues for the six months ended December 31, 2005 increased to $9.1 million compared to $300,000 for the prior year period. Drilling revenue is earned under daywork contracts where we provide a drilling rig with required personnel to our third party customers who supervise the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is in use. During the mobilization period we typically earn a fixed amount of revenue based on the mobilization rate set in the contract. Drilling revenues earned on wells drilled for Delta have been eliminated through consolidation. At December 31, 2005 there were eight DHS rigs in operation compared to four rigs in operation at June 30, 2005.

Trucking revenues were insignificant during the six months ended December 31, 2005 as the Chapman acquisition was completed in November 2005.

Production and Cost Information

Production volumes, average prices received and cost per equivalent Mcf for the six months ended December 31, 2005 and 2004 are as follows:

	Six Months Ended December 31,			
	2005[(1)]		2004[(1)]	
	Onshore	Offshore	Onshore	Offshore
Production – Continuing Operations:				
Oil (MBbl)	264	81	159	74
Gas (MMcf)	2,634	-	1,870	-
Production – Discontinued Operations:				
Oil (MBbl)	164	-	272	-
Gas (MMcf)	931	-	1,427	-
Total Production (MMcfe)	6,285	485	5,884	444
Average Price – Continuing Operations:				
Oil (per barrel)	$ 59.62	$ 47.12	$ 45.41	$ 30.66
Gas (per Mcf)	$ 8.78	$ -	$ 5.56	$ -
Costs per Mcfe – Continuing Operations:				
Hedge gain (loss)	$ (.81)	$ -	$ (.03)	$ -
Lease operating expense	$ 1.01	$ 4.62	$ 0.57	$ 3.56
Production taxes (benefit)	$ .61	$ (.23)	$ .54	$ .06
Transportation costs	$ .16	$ -	$ .03	$ -
Depletion expense	$ 2.73	$ .79	$ 1.40	$ .75

(1) Revised for operations discontinued in 2007.

Lease Operating Expense. Lease operating expenses for the six months ended December 31, 2005 were $6.5 million compared to $3.2 million for the same period a year earlier. Lease operating expense from continuing operations for onshore properties for the six months ended December 31, 2005 was $1.01 per Mcfe as compared to $0.57 per Mcfe for the same period a year earlier. Lease operating expense from continuing operations for offshore properties was $4.62 per Mcfe for the six months ended December 31, 2005 and $3.56 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 increase in the percentage of wells owned in the Gulf Coast Region, largely due to the Manti acquisition in January 2005, as compared to our other regions. Our Gulf Coast properties typically have higher average lease operating costs. Newton also experienced substantial costs related to compression and salt water hauling and disposal.

Depreciation, Depletion and Amortization – oil and gas. Depreciation, depletion and amortization expense increased 155% to $12.4 million in the six months ended December 31, 2005, as compared to $4.9 million for the six months ended December 31, 2004. Depreciation expenses for our onshore properties increased to $2.73 per Mcfe during the six months ended December 31, 2005 from $1.40 per Mcfe for the six months ended December 31, 2004. Depletion rates have increased based on the higher amounts paid to acquire reserves in the ground and the increase in drilling costs relative to reserve additions. We also incurred higher depletion rates caused by lower proved developed producing reserves in our South Angleton field from unsuccessful drilling results.

Depreciation and Amortization – drilling and trucking. Depreciation and amortization expense – drilling and trucking increased to $2.8 million for the six months ended December 31, 2005 as compared to $386,000 for the prior year period. This increase can be attributed to additional rigs acquired by DHS Drilling Company.

Exploration Expense. Exploration expense consists of geological and geophysical costs and lease rentals. Our exploration costs for the six months ended December 31, 2005 were $2.1 million compared to $1.3 million for the six months ended December 31, 2004. The increase in exploration costs was primarily related to seismic costs and impairment of prospect acquisition costs. During the six months ended December 31, 2005, our most significant exploration cost related to the $1.4 million Newton 3D seismic shoot covering 58 square miles which was completed and processed during 2005 and which assisted us in prioritizing our drilling locations and identifying target formations. In addition, we acquired 2D data in the Gulf Coast Region and also began acquiring geophysical data on the Columbia River Basin properties in the state of Washington.

Dry Hole Costs and Impairments. We incurred dry hole costs of approximately $4.1 million for the six months ended December 31, 2005 compared to $2.7 million for the same period a year ago. During 2004, a significant portion of these costs related to our Trail Blazer prospect in Laramie County, Wyoming and four non-Niobrara formation dry holes in Washington County, Colorado. During the six months ended December 31, 2005, four dry holes were drilled including two in Washington County, Colorado, one in Utah, and one in Orange County, California.

During the six months ended December 31, 2005, a dry hole was drilled on a prospect located in Orange County, California. Based on drilling results and evaluation of the prospect, we determined that we would not pursue development and accordingly, an impairment of $1.3 million was recorded for the full impairment of the remaining leasehold costs related to the prospect.

Drilling and Trucking Operations. We had drilling and trucking operations of $5.8 million during the six months ended December 31, 2005 compared to $1.1 million during the six months ended December 31, 2004. The significant increase in expenses was due to an increase in the number of rigs in operation, eight rigs as of December 31, 2005 compared to two rigs at December 31, 2004.

General and Administrative Expense. General and administrative expense increased 137% to $16.5 million for the six months ended December 31, 2005 as compared to $7.0 million for the six months ended December 31, 2004. The increase in general and administrative expenses is primarily attributed to $2.1 million of stock option compensation expense related to the adoption of SFAS No. 123 (Revised 2004), "Share Based Payment" ("SFAS 123R"), $1.4 million increase in professional fees attributed largely to compliance with the Sarbanes-Oxley Act, a 60% increase in technical and administrative staff and related personnel costs, the expansion of our office facility and $715,000 of vested restricted stock and option awards granted to officers, directors and management.

Gain on Sale of Marketable Security. During the six months ended December 31, 2005, the Company sold investment securities classified as available-for-sale securities resulting in a realized gain of $1.2 million.

Losses on Ineffective Derivative Instruments, Net. During the six months ended December 31, 2005, our gas derivative contracts became ineffective and no longer qualified for hedge accounting. Hedge ineffectiveness results from different changes in the NYMEX contract terms and the physical location, grade and quality of our oil and gas production. The change in fair value of our gas contracts in the six month period are reflected in earnings, as opposed to being recorded in other comprehensive income (loss), a component of stockholders' equity. As a result, we recognized a $14.4 million loss in our statement of operations. As commodity prices fluctuate, we will record our gas derivative contracts at market value with any changes in market value recorded through unrealized gain (loss) on derivative contracts in our statement of operations. Our oil derivative contracts continue to qualify for hedge accounting.

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. During the six months ended December 31, 2004, Big Dog and Shark incurred operating losses. During the six months ended December 31, 2005, DHS generated an operating profit.

Interest and Financing Costs. Interest and financing costs increased 302% to $8.9 million for the six months ended December 31, 2005, as compared to $2.2 million for the six months ended December 31, 2004. The increase is primarily related to interest on the $150.0 million senior notes that were issued in March 2005, 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 Basin prospect in Washington completed in April 2005. In addition, borrowings of $35.0 million by DHS in 2005 also resulted in increased interest expense.

Income tax benefit. Prior to June 30, 2005, the Company recorded a full valuation allowance on its deferred tax assets and accordingly, during the six months ended December 31, 2004, no income tax provision was recorded. During the six months ended December 31, 2005, an income tax benefit of $10.9 million was recorded for continuing operations at an effective tax rate of 37.2%.

Discontinued Operations. On September 2, 2005, we completed the sale of our Deerlick Creek field in Tuscaloosa County, Alabama for $30.0 million with an effective date of July 1, 2005. We recorded a gain on sale of oil and gas properties of $10.2 million on net proceeds of $28.9 million after normal closing adjustments. Income from discontinued operations of properties sold has been restated to include the Deerlick Field sold in September 2005, Frisco Field sold in June 2006, East Texas properties and Pennsylvania properties acquired in the Castle acquisition which were sold in August 2006, the Company's Kansas field sold in January 2007, the Australia field and the New Mexico and East Texas properties, which were sold in March 2007, the North Dakota properties sold in September 2007, the Washington County, Colorado properties sold in October 2007, and the Midway Loop, Texas properties held for sale at December 31, 2007. The results of operations on these assets during the six months ended December 31, 2005 and 2004 were $6.0 million and $12.8 million, respectively.

Liquidity and Capital Resources

Liquidity is a measure of a company's ability to access cash. In February 2008, we significantly improved our liquidity position with $684 million in gross proceeds from the sale of 36 million shares to Tracinda Corporation. As of December 31, 2007, our corporate rating and senior unsecured debt rating were Caa1 and Caa2, respectively, as issued by Moody's Investors Service. Moody's outlook is "stable." As of December 31, 2007, our corporate credit and senior unsecured debt ratings were B- and CCC+, respectively, as issued by Standard and Poor's ("S&P"). S&P's outlook on the rating was "stable." Subsequent to year end, S&P placed the ratings on CreditWatch with positive implications following the announced investment by Tracinda Corporation. We have completed several equity, debt, and property transactions in the past year as described below. On January 25, 2007, we completed a public offering of 2,768,000 shares of our common stock for net proceeds of $56.4 million. During the year ended December 31, 2007, we sold non-core properties in Kansas, Texas, New Mexico, Australia, and North Dakota for combined net proceeds of $46.4 million. On April 25, 2007, we issued 7,130,000 shares of common stock at $20.50 per share and issued $115.0 million aggregate principal amount of 3¾% Senior Convertible Notes due 2037 for total net proceeds of $251.9 million after underwriters' discounts and commissions of $9.3 million.

Our cash requirements are largely dependent upon the number and timing of projects included in our capital development plan, most of which are discretionary. We have historically addressed our long-term liquidity requirements through the issuance of debt and equity securities when market conditions permit, through cash provided by operating activities, sales of oil and gas properties, and through borrowings under our credit facility.

During the year ended December 31, 2007, we had an operating loss of $131.3 million, but generated cash from operating activities of $84.4 million and obtained cash from financing activities of $243.1 million. During this period we spent $286.3 million on oil and gas development (or $332.5 million, net of $46.2 million proceeds from dispositions), $4.5 million on oil and gas acquisitions, and $15.2 million on drilling and trucking capital expenditures (or $22.3 million, net of $7.1 million proceeds from dispositions). At December 31, 2007, we had $10.1 million in cash, total assets of $1.1 billion and a debt to capitalization ratio of 44.9%. Long-term debt at December 31, 2007 totaled $413.1 million, comprised of $148.6 million of bank debt, $149.5 million of senior subordinated notes and $115.0 million of senior convertible notes. In April 2007 and again in February 2008, our credit facility was paid down in full with proceeds from our debt and equity offerings. Available borrowing capacity under our bank credit facility at December 31, 2007 was approximately $140.0 million with a balance outstanding of $73.6 million. In December 2007, DHS closed a new $75.0 million credit facility with Lehman Brothers Commercial Paper, as administrative agent. DHS has no additional availability under its credit facility.

At December 31, 2007, we were in compliance with our quarterly financial covenants. Our covenants require a minimum 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 4.0 to 1 for the quarter ended December 31, 2007, and 3.75 to 1 for the end of each quarter thereafter. These financial covenant calculations only reflect wholly-owned subsidiaries.

The prices we receive for future oil and natural gas production and the level of production have a significant impact on our 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 and the success of our exploration and production activities in generating additions to production.

Although we believe that through cash on hand, availability on our credit facility, and cash flows from operations, we have access to adequate capital to fund our development plans, we continue to examine additional sources of long-term capital, including a restructured debt facility, the issuance of debt instruments, the sale of preferred and 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, many of which are beyond our control.

Company Acquisitions and Growth

We continue to evaluate potential acquisitions and property development opportunities. During the year ended December 31, 2007, we completed the following transactions:

On October 1, 2007, we completed an asset exchange transaction to acquire an additional 12.5% working interest in the Garden Gulch Field in the Piceance Basin, in exchange for our assets in Washington County, Colorado and $33.0 million in cash.

On June 8, 2007, we acquired a 50% non-controlling ownership interest in Delta Oilfield Tank Company, LLC ("Delta Oilfield") for cash consideration of $4.0 million. Delta Oilfield will be accounted for using the equity method of accounting and is an unconsolidated affiliate of the Company.

On June 8, 2007, we issued 475,000 shares of common stock valued at approximately $9.9 million for additional interest in a well owned and operated by the Company, and additional interest in a non-operated well.

On March 9, 2007, we issued 754,000 shares of common stock valued at approximately $13.8 million for additional interests in two wells already owned and operated by us located in Polk County, Texas.

On March 5, 2007, DHS purchased a drilling rig ("Rig 18") for $7.6 million. The rig is a 700 horsepower rig with a depth rating of 10,500 feet. The rig is currently operating in the Rocky Mountain Region.

On March 1, 2007, we paid $3.5 million for 39,000 net acres and interests in several wells in Fremont County, Wyoming.

Historical Cash Flow

Our cash flow from operating activities increased from $53.4 million for the year ended December 31, 2006 to $84.4 million for the year ended December 31, 2007, primarily as a result of changes in working capital. Our net cash used in investing activities increased to $325.0 million for the year ended December 31, 2007 compared to net cash used in investing activities of $203.1 million for the year earlier period, primarily due to our increased drilling activity. Cash provided by financing activities was $243.1 million for the year ended December 31, 2007 compared to $151.8 million for the comparable prior year period. Cash provided by financing activities was higher in 2007 primarily due to cash received in April from our convertible debt and equity offerings.

Our cash flow from operating activities increased 5% to $53.4 million for the year ended December 31, 2006 compared to $50.7 million for the same period a year earlier. Our net cash used in investing activities decreased by 32% to $203.1 million for the year ended December 31, 2006 compared to $297.2 million for the same period a year earlier. The decrease in cash used for investing activity can be attributed to a reduction in property acquisitions due to an increased focus on drilling activities. Cash flow from financing activities decreased to $151.8 million for the year ended December 31, 2006 compared to $250.6 million for the same period the prior year. During the year ended December 31, 2006, we financed our operations, acquisitions, and capital expenditures primarily with net proceeds of $33.9 million in newly issued equity and $118.3 million in net debt additions.

Capital and Exploration Expenditures and Financing

Our capital and exploration expenditures and sources of financing for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and year ended June 30, 2005 were as follows:

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
CAPITAL AND EXPLORATION EXPENDITURES:	(In thousands)			
Acquisitions:				
Garden Gulch	$ 34,778	$ -	$ -	$ -
Austin Chalk incremental interests	23,765	-	-	-
Wyoming (Yates)	3,500	-	-	-
Washington County, South and North Tongue	1,000	-	828	10,571
Armstrong Acquisition	-	40,103	-	-
Castle	-	33,648	-	-
Savant Acquisition	-	-	85,000	-
Manti	-	-	-	59,700
Columbia River Basin	-	-	-	18,255
Sacramento Basin	-	-	-	10,400
Karnes County, Texas	-	-	-	5,000
Other	9,988	24,678	7,904	2,718
Other development costs	287,790	179,874	86,871	102,216
Drilling and trucking companies	22,292	63,848	25,733	32,690
Exploration costs	9,062	4,690	2,061	6,155
	$ 392,175	$ 346,841	$ 208,397	$ 247,705
FINANCING SOURCES:				
Cash flow provided by operating activities	78,173	$ 53,386	$ 24,879	$ 44,862
Stock issued for cash upon exercised options	137	3,711	1,166	132
Stock issued for cash, net	202,084	33,870	95,026	-
Net long-term borrowings	40,836	114,265	28,715	139,051
Proceeds from sale of oil and gas properties	46,193	82,716	34,178	18,721
Proceeds from sale of drilling assets	7,145	-	-	-
Investments in and notes issued to affiliates	(12,440)	-	-	-
Minority interest contributions	(355)	9,018	-	14,800
Other	(106)	(3,646)	2,566	63
	$ 361,667	$ 293,320	$ 186,530	$ 217,629

We anticipate our drilling expenditures to range between $350.0 and $370.0 million for the year ending December 31, 2008 based on expected cash flow from operations and anticipated other property or equity transactions during the course of 2008. The timing of a portion of our capital expenditures is discretionary and could be delayed or curtailed, if necessary.

Sale of Oil and Gas Properties - Discontinued Operations

On October 1, 2007, we divested our Washington County, Colorado assets in conjunction with an asset exchange transaction to acquire additional working interest in the Garden Gulch Field in the Piceance Basin.

On September 4, 2007, we completed the sale of certain non-core properties located in North Dakota for cash consideration of approximately $6.2 million. The sale resulted in a gain of $4.3 million.

On March 30, 2007, we completed the sale of certain non-core properties located in New Mexico and East Texas for cash consideration of approximately $31.5 million, prior to customary purchase price adjustments. The sale resulted in a loss of approximately $10.8 million.

On March 27, 2007, we completed the sale of certain non-core properties located in Australia for cash consideration of approximately $6.0 million. The sale resulted in an after-tax gain of $2.0 million.
On January 10, 2007, we completed the sale of certain non-core properties located in Padgett field, Kansas for cash consideration of $5.6 million. The transaction resulted in a gain on sale of properties of $297,000.

In March 2006, we sold approximately 26% of PGR for $20.4 million. This transaction involved both proved and unproved property interests and accordingly, to the extent the sale of PGR related to unproved properties, no gain could be recognized as all of the unproved cost basis was not yet recovered. We recorded a gain of $5.9 million, $3.7 million net of tax, and a $3.4 million reduction to property during the first quarter of 2006 as a result of the transaction. We have retained a 74% interest in PGR.

During December 2005, we transferred our ownership in approximately 427,000 gross acres (64,000 net acres) of non-operated interests in the Columbia River Basin to a newly created wholly owned subsidiary, CRBP. In January and March 2006, we sold a combined 44% minority interest in CRBP for total proceeds of $32.8 million. As the sale involved unproved properties, no gain on the partial sale of CRBP could be recognized until all of the cost basis of CRBP had been recovered. Accordingly, we recorded a $13.0 million gain, ($8.1 million net of tax) and an $11.2 million reduction to property during the first quarter of 2006 as a result of closing the transaction.

Also included in discontinued operations are our Midway Loop, Texas oil and gas properties which are held for sale as of December 31, 2007.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Contractual and Long-Term Debt Obligations

	Payments Due by Period				
Contractual Obligations at December 31, 2007	Less than 1 year	1-3 Years	3-5 Years	More than 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	31,033	83,533
3¾% Senior convertible notes	-	-	-	115,000	115,000
Credit facility	-	73,600	-	-	73,600
Term loan – DHS	-	75,000	-	-	75,000
Derivative liability	6,295	-	-	-	6,295
Abandonment retirement obligation	1,045	431	454	10,449	12,379
Operating leases	3,527	5,331	2,997	2,394	14,249
Drilling commitments	3,500	14,000	-	-	17,500
Other debt obligations	13	-	-	-	13
Total contractual cash obligations	$ 24,880	$189,362	$ 24,451	$308,876	$ 547,569

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 semi-annually 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 located in the Gulf Coast Region. 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.

3¾% Senior Convertible Notes, due 2037

On April 25, 2007, we issued $115.0 million aggregate principal amount of 3¾% Senior Convertible Notes due 2037 (the "Notes") for net proceeds of $111.6 million after underwriters' discounts and commissions of approximately $3.4 million. The Notes bear interest at a rate of 3¾% per annum, payable semi-annually in arrears, on May 1 and November 1 of each year, beginning November 1, 2007. The Notes will mature on May 1, 2037 unless earlier converted, redeemed or repurchased. The Notes will be convertible at the holder's option, in whole or in part, at an initial conversion rate of 32.9598 shares of common stock per $1,000 principal amount of Notes (equivalent to a conversion price of approximately $30.34 per share) at any time prior to the close of business on the business day immediately preceding the final maturity date of the Notes, subject to prior repurchase of the Notes. The conversion rate may be adjusted from time to time in certain instances. Upon conversion of a Note, we will have the option to deliver shares of our common stock, cash or a combination of cash and shares of our common stock for the Notes surrendered. In addition, following certain fundamental changes that occur prior to maturity, we will increase the conversion rate for a holder who elects to convert its Notes in connection with such fundamental changes by a number of additional shares of common stock. Although the Notes do not contain any financial covenants, the Notes contain covenants that require us to properly make payments of principal and interest, provide certain reports, certificates and notices to the trustee under various circumstances, cause our wholly-owned subsidiaries to become guarantors of the debt, maintain an office or agency where the Notes may be presented or surrendered for payment, continue our corporate existence, pay taxes and other claims, and not seek protection from the debt under any applicable usury laws.

Credit Facility

At December 31, 2007, the $250.0 million credit facility had $73.6 million outstanding. On February 20, 2008, the credit facility was fully paid down with a portion of the proceeds from our equity offering. 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. 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) ratio of less than 4.0 to 1 for the quarter ended December 31, 2007, and 3.75 to 1 for the end of each quarter thereafter. The financial covenants only include subsidiaries which we own 100%. At December 31, 2007, we were in compliance with our quarterly debt covenants and restrictions.

The borrowing base is re-determined by the lending banks at least semi-annually on April 1 and October 1 of each year, or by special re-determinations if requested by the Company based on drilling success. 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, (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. There was no change to our borrowing base as a result of the October 2007 re-determination.

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.

Unsecured Term Loan

In December 2006 we entered into an agreement with JP Morgan Chase Bank N.A. for a $25.0 million unsecured term loan with interest at LIBOR plus a margin of 3.5% at December 31, 2006. The note was paid in full in January 2007 with the proceeds from the $56.4 million equity offering.

Credit Facility – DHS

On December 20, 2007, DHS entered into a new $75.0 million credit agreement with Lehman Commercial Paper Inc. The proceeds were used to pay off the JP Morgan credit facility. The credit facility has a variable interest rate based on 90-day LIBOR plus a fixed margin of 5.50% and matures on December 31, 2010. Annual principal payments are based upon a calculation of excess cash flow (as defined) for the preceding year. DHS is required to meet certain financial covenants quarterly beginning March 31, 2008 including (i) consolidated EBITDA for four consecutive fiscal quarters must be greater than $20.0 million; (ii) Consolidated Leverage Ratio (as defined) for four consecutive fiscal quarters cannot exceed 3.50 to 1.00; (iii) Consolidated Interest Coverage Ratio (as defined) for four consecutive fiscal quarters must exceed 2.50 to 1.00 and (iv) the Current Ratio for any fiscal quarter must be greater than 1.0 to 1.0. DHS incurred $1.3 million of financing charges in conjunction with the agreement which will be amortized over the life of the loan.

On May 4, 2006, DHS entered into a $100.0 million senior secured credit facility with JP Morgan Chase Bank, N.A. Proceeds from the $75.0 million initial draw were used to pay off the Guggenheim term loan, complete the acquisition of C&L Drilling, finance additional capital expenditures and pay transaction expenses. In December 2007, DHS used proceeds from the Lehman credit agreement and the sale of Rigs 2 and 3 to pay off the $79.7 million outstanding balance of the JP Morgan senior secured credit facility.

Term Loan - DHS

On May 4, 2006, DHS used proceeds from the JP Morgan credit facility to pay off the remaining balance of the previously outstanding term loan of approximately $41.0 million.

Other Contractual Obligations

Our asset retirement obligation arises from the costs necessary to plug and abandon our oil and gas wells. The majority of this obligation will not occur during the next five years.

We lease our corporate office in Denver, Colorado under an operating lease which will expire in 2014. Our average yearly payments approximate $1.6 million 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.

In March 2007, we executed an earn-in agreement with EnCana whereby we can earn up to 6,000 net acres in the Piceance Basin with the drilling of 128 wells during the next 36 months. We are committed to drill 64 total wells, eight of which were drilled by October 31, 2007. The remaining wells are required to be drilled by June 1, 2009. We are liable for $250,000 per undrilled well in the event the drilling obligations are not met.

Derivative instruments represent the net estimated unrealized losses for our oil and gas hedges at December 31, 2007. The ultimate settlement amounts of these hedges are unknown because they are subject to continuing market risk. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk."

The following table summarizes our derivative contracts outstanding at December 31, 2007:

Commodity	Volume		Price Floor / Price Ceiling	Term	Index	Net Fair Value Asset (Liability) at December 31, 2007 (In thousands)
Crude oil	1,200	Bbls / day	$ 65.00 / $ 80.03	Jan '08 - Mar '08	NYMEX – WTI	$ (1,705)
Crude oil	1,200	Bbls / day	$ 65.00 / $ 79.77	Apr '08 - June '08	NYMEX – WTI	(1,620)
Crude oil	1,200	Bbls / day	$ 65.00 / $ 79.86	July '08 - Sept '08	NYMEX – WTI	(1,522)
Crude oil	1,200	Bbls / day	$ 65.00 / $ 79.83	Oct '08 - Dec '08	NYMEX – WTI	(1,448)
Natural gas	15,000	MMBtu / day	$ 6.50 / $ 8.30	Jan '08 - Dec '08	CIG	2,404
Natural gas	5,000	MMBtu / day	$ 6.50 / $ 8.40	Jan '08 - Mar '08	CIG	211
Natural gas	10,000	MMBtu / day	$ 6.00 / $ 7.25	Apr '08 -Sept '08	CIG	139
Natural gas	10,000	MMBtu / day	$ 6.50 / $ 7.90	Oct '08 - Dec '08	CIG	176
						$ (3,365)

The fair value of our derivative instruments liability was a $3.4 million loss at December 31, 2007. Subsequent to year-end, we entered into new CIG gas hedges for 10,000 Mmbtu per day for the second and third quarters of 2008 with a floor price of $6.50 and ceiling prices of $7.70 and $8.15 per Mmbtu, respectively. We also entered into new CIG gas hedges for 35,000 Mmbtu per day for the first quarter of 2009 with a floor price of $7.50 per Mmbtu and a ceiling price of $9.88 per Mmbtu. The fair value of our derivative liability at February 26, 2008 was $15.2 million.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations were based on 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 2 to our consolidated financial statements. 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 are 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 the 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 costs incurred to select development locations within an oil and gas field are typically considered development costs and are 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 quarterly or 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 production costs, 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. 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 during the year ended December 31, 2007, an impairment of $58.4 million was recorded primarily related to the Howard Ranch and Fuller fields in Wyoming ($37.5 million and $10.3 million, respectively), and the South Angleton field in Texas ($9.7 million), primarily due to lower Rocky Mountain natural gas prices and marginally economic deep zones on the Howard Ranch Prospect. During the year ended December 31, 2006, an impairment of $10.4 million was recorded on certain of the Company's eastern Colorado properties primarily due to lower Rocky Mountain natural gas prices. In addition, an impairment of $1.0 million was recorded on certain Oklahoma properties. The Company recorded no impairment provision attributable to developed properties for the six months ended December 31, 2005 and the year ended June 30, 2005. For fiscal year 2008, we are continuing to develop and evaluate certain proved and unproved properties on which favorable or unfavorable results or commodity prices may cause us to revise in future quarters our estimates of those properties' future cash flows. Such revisions of estimates could require us to record an impairment in the period of such revisions.

Commodity Derivative Instruments and Hedging Activities

We may periodically enter into commodity derivative contracts or fixed-price physical contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize futures 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.

All derivative instruments are recorded on the balance sheet at fair value. Effective July 1, 2007, we elected to discontinue cash flow hedge accounting prospectively. Beginning July 1, 2007, we recognize mark-to-market gains and losses in current earnings instead of deferring those amounts in accumulated other comprehensive income.

Asset Retirement Obligation

We account for our asset retirement obligations under SFAS 143. SFAS 143 requires entities to record the fair value of a liability for retirement obligations of acquired assets. The Company's asset retirement obligations arise from the plugging and abandonment liabilities for its oil and gas wells.

In March 2005, the FASB issued FASB Interpretation 47 ("FIN 47"), an interpretation of SFAS 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). FIN 47 clarifies the term "conditional asset retirement obligation" as it is used in SFAS 143. The Company applied the guidance of FIN 47 beginning July 1, 2005, resulting in no impact on its financial statements.

Deferred Tax Asset Valuation Allowance

We follow SFAS 109 to account for our deferred tax assets and liabilities. Under SFAS 109, deferred tax assets and liabilities are recognized for the estimated future tax effects attributable to temporary differences and carryforwards. Ultimately, realization of a deferred tax benefit depends on the existence of sufficient taxable income within the carryback/carryforward period to absorb future deductible temporary differences or a carryforward. In assessing the realizability of deferred tax assets, management must consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. Management considers all available evidence (both positive and negative) in determining whether a valuation allowance is required. Such evidence includes the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment, and judgment is required in considering the relative weight of negative and positive evidence. As a result of management's current assessment, we maintain a significant valuation allowance against our deferred tax assets. We will continue to monitor facts and circumstances in our reassessment of the likelihood that operating loss carryforwards and other deferred tax attributes will be utilized prior to their expiration. As a result, we may determine that the deferred tax asset valuation allowance should be increased or decreased. Such changes would impact net income through offsetting changes in income tax expense or benefit.

Recently Issued Accounting Standards and Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "Business Combinations" ("SFAS 141R"), which replaces SFAS 141. SFAS 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any resulting goodwill, and any noncontrolling interest in the acquiree. The Statement also provides for disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008, or our fiscal year 2009, and must be applied prospectively to business combinations completed on or after that date. We will evaluate how the new requirements could impact the accounting for any acquisitions completed beginning in fiscal 2009 and beyond, and the potential impact on our consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of Accounting Research Bulletin No. 51" ("SFAS 160"), which establishes accounting and reporting standards for noncontrolling interests ("minority interests") in subsidiaries. SFAS 160 clarifies that a noncontrolling interest in a subsidiary should be accounted for as a component of equity separate from the parent's equity. SFAS 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008, or our fiscal year 2009, and must be applied prospectively, except for the presentation and disclosure requirements, which will apply retrospectively. We are currently evaluating the potential impact of the adoption of SFAS 160 on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"). SFAS 159 permits companies to choose to measure many financial instruments and certain other items at fair value. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, or fiscal year 2008. We have not yet determined if we will elect to apply any of the provisions of SFAS 159 or what effect the adoption of the Statement would have, if any, on our consolidated financial statements.

Effective January 1, 2007, we adopted provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109" ("FIN 48"). FIN 48 provides detailed guidance for the financial statement recognition, measurement and disclosure of uncertain tax positions recognized in the financial statements in accordance with SFAS 109. Tax positions must meet a "more-likely-than-not" recognition threshold at the effective date to be recognized upon the adoption of FIN 48 and in subsequent periods. Upon the adoption of FIN 48, we had no unrecognized tax benefits. During the year ended December 31, 2007, no adjustments were recognized for uncertain tax benefits.

We recognize interest and penalties related to uncertain tax positions in income tax benefit/expense. No interest and penalties related to uncertain tax positions were accrued at December 31, 2007.

The tax years 2003 through 2006 for federal returns and 2002 through 2006 for state returns remain open to examination by the major taxing jurisdictions in which we operate, although no material changes to unrecognized tax positions are expected within the next twelve months.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and requires additional disclosures about fair value measurements. SFAS 157 aims to improve the consistency and comparability of fair value measurements by creating a single definition of fair value. The Statement emphasizes that fair value is not entity-specific, but instead is a market-based measurement of an asset or liability. SFAS 157 upholds the requirements of previously issued pronouncements concerning fair value measurements and expands the required disclosures. This Statement is effective for fiscal year commencing January 1, 2008. We do not expect the impact of SFAS 157 to be material to our financial condition or results of operations. We anticipate the primary impact of the standard will be additional disclosures related to the measurement of fair value in the Company's recurring impairment test calculations related to oil and gas properties, drilling rigs, and goodwill, the valuation of oil and gas derivative financial instruments, and the valuation of assets acquired or liabilities assumed in future business combinations, if any.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Rate and Price Risk

We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, including costless collars, swaps, and puts. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy. We use hedges to limit the risk of fluctuating cash flows that fund our capital expenditure program. We also may use hedges in conjunction with acquisitions to achieve expected economic returns during the payout period.

The net fair value of our derivative instruments was a $3.4 million liability at December 31, 2007 and a $15.2 million liability on February 26, 2008.

As of February 26, 2008, our derivative contracts cover approximately 12.2 Bcfe of our 2008 production. Assuming production and the percent of oil and gas sold remained unchanged from the year ended December 31, 2007, a hypothetical 10% decline in the average market price the Company realized during the year ended December 31, 2007 on unhedged production would reduce the Company's oil and natural gas revenues by approximately $9.5 million on an annual basis.

Interest Rate Risk

We were subject to interest rate risk on $148.6 million of variable rate debt obligations at December 31, 2007. The annual effect of a 10% change in interest rates would be approximately $1.3 million. The interest rate on these variable debt obligations approximates current market rates as of December 31, 2007.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Delta Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Delta Petroleum Corporation and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, changes in stockholders' equity and comprehensive income (loss), and cash flows for the years ended December 31, 2007 and 2006, the six months ended December 31, 2005 and the year ended June 30, 2005. 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 December 31, 2007 and 2006, and the results of their operations and their cash flows for the years ended December 31, 2007 and 2006, the six months ended December 31, 2005 and the year ended June 30, 2005, 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), Delta Petroleum Corporation's internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

As discussed in note 2 to the consolidated financial statements, Delta Petroleum Corporation adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109,* effective January 1, 2007 and Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment,* effective July 1, 2005.

/s/ KPMG LLP

Denver, Colorado
February 28, 2008

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,091	$ 7,666
Assets held for sale	62,744	31,822
Trade accounts receivable, net of allowance for doubtful accounts, of $664 and $100, respectively	38,761	29,503
Prepaid assets	3,943	4,384
Inventory	4,236	2,851
Derivative instruments	2,930	10,799
Deferred tax asset	150	-
Other current assets	10,214	2,769
Total current assets	133,069	89,794
Property and equipment:		
Oil and gas properties, successful efforts method of accounting:		
Unproved	247,466	217,573
Proved	740,408	564,242
Drilling and trucking equipment	146,097	136,038
Pipeline and gathering system	22,140	14,909
Other	19,069	13,983
Total property and equipment	1,175,180	946,745
Less accumulated depreciation and depletion	(245,153)	(131,545)
Net property and equipment	930,027	815,200
Long-term assets:		
Marketable securities	6,268	-
Deferred financing costs	7,187	6,928
Goodwill	7,747	7,747
Other long-term assets	10,616	6,722
Investment in unconsolidated affiliates	10,281	2,932
Total long-term assets	42,099	24,329
Total assets	$ 1,105,195	$ 929,323
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 13	$ 816
Accounts payable	119,783	84,439
Other accrued liabilities	17,105	10,818
Deferred tax liability	-	2,893
Derivative instruments	6,295	613
Total current liabilities	143,196	99,579
Long-term liabilities:		
7% Senior notes, unsecured	149,459	149,384
3 ¾% Senior convertible notes	115,000	-
Credit facility	73,600	118,000
Unsecured term loan	-	25,000
Credit facility/Term loan – DHS	75,000	74,050
Asset retirement obligation	4,154	4,013
Deferred tax liability	9,085	3,660
Other debt, net	-	14
Total long-term liabilities	426,298	374,121
Minority interest	27,296	27,390
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $.01 par value: authorized 3,000,000 shares, none issued	-	-
Common stock, $.01 par value; authorized 300,000,000 shares, issued 66,429,000 shares at December 31, 2007, and 53,439,000 shares at December 31, 2006	664	534
Additional paid-in capital	664,733	430,479
Accumulated other comprehensive income	-	4,865
Accumulated deficit	(156,992)	(7,645)
Total stockholders' equity	508,405	428,233
Total liabilities and stockholders' equity	$ 1,105,195	$ 929,323

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2007	Years Ended December 31, 2006	Six Months Ended December 31, 2005	Year Ended June 30, 2005
	(In thousands, except per share amounts)			
Revenue:				
Oil and gas sales	$ 94,559	$ 94,223	$ 42,643	$ 52,446
Contract drilling and trucking fees	56,777	57,149	9,096	4,796
Gain (loss) on effective derivative instruments, net	12,854	(4,712)	(3,413)	(630)
Total revenue	164,190	146,660	48,326	56,612
Operating expenses:				
Lease operating expense	20,142	17,655	6,507	9,291
Transportation expense	3,684	978	680	394
Production taxes	5,559	4,784	2,455	3,415
Depreciation, depletion, accretion and amortization – oil and gas	63,373	53,980	12,411	14,055
Depreciation and amortization – drilling and trucking	22,052	16,404	2,847	1,525
Exploration expense	9,062	4,690	2,061	6,155
Dry hole costs and impairments	85,084	15,682	5,423	2,771
Drilling and trucking operations	36,954	34,163	5,821	4,666
General and administrative	49,621	35,696	16,491	16,930
Gain on sale of oil and gas properties	-	(20,034)	-	-
Total operating expenses	295,531	163,998	54,696	59,202
Operating income (loss)	(131,341)	(17,338)	(6,370)	(2,590)
Other income and (expense):				
Other income (expense)	376	(154)	(36)	(570)
Gain (loss) on ineffective derivative instruments, net	(2,902)	11,722	(14,437)	(330)
Gain on sale of marketable securities, net	-	-	1,194	-
Gain on sale of investment in LNG	-	1,058	-	-
Minority interest	1,231	(2,595)	(688)	1,017
Losses from unconsolidated affiliates	(393)	-	-	-
Interest and financing costs	(27,199)	(26,316)	(8,866)	(7,880)
Total other expense	(28,887)	(16,285)	(22,833)	(7,763)
Loss from continuing operations before income taxes and discontinued operations	(160,228)	(33,623)	(29,203)	(10,353)
Income tax benefit (expense)	(2,677)	12,623	10,873	11,969
Income (loss) from continuing operations	(162,905)	(21,000)	(18,330)	1,616
Discontinued operations:				
Income from discontinued operations of properties sold, net of tax	17,556	9,163	5,952	13,434
Gain (loss) on sale of discontinued operations, net of tax	(3,998)	6,712	11,788	-
Income (loss) before extraordinary gain, net of tax	(149,347)	(5,125)	(590)	15,050
Extraordinary gain, net of tax	-	5,560	-	-
Net income (loss)	$ (149,347)	$ 435	$ (590)	$ 15,050
Basic income (loss) per common share:				
Income (loss) from continuing operations	$ (2.66)	$ (.41)	$ (.41)	$ .04
Discontinued operations	.22	.31	.40	.33
Extraordinary gain, net of tax	-	.11	-	-
Net income (loss)	$ (2.44)	$ .01	$ (.01)	$ .37
Diluted income (loss) per common share:				
Income (loss) from continuing operations	$ (2.66)	$ (.39)	$ (.41)	$ .04
Discontinued operations	.22	.30	.40	.32
Extraordinary gain, net of tax	-	.10	-	-
Net income (loss)	$ (2.44)	$ .01	$ (.01)	$ .36

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

(In thousands, except per share amounts)

	Common stock Shares	Common stock Amount	Additional paid-in capital	Accumulated other comprehensive income/(loss)	Comprehensive income (loss)	Unearned Compensation	Accumulated deficit	Total
Balance, July 1, 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	1,793	18	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
Comprehensive income:								
Net loss	-	-	-	-	$ (590)		(590)	(590)
Other comprehensive income transactions, net of tax								
Realized gain on equity securities sold, net of tax expense of $458	-	-	-	(736)	(736)		-	(736)
Hedging loss reclassified to income upon settlement, net of tax benefit of $1,733	-	-	-	2,398	2,398		-	2,398
Change in fair value of derivative hedging instruments, net of tax benefit of $1,036	-	-	-	(1,434)	(1,434)		-	(1,434)
Comprehensive loss					$ (362)			
Shares issued for oil and gas properties	50	1	827	-			-	828
Shares issued for cash, net of offering costs	5,405	54	94,917	-			-	94,971
Shares issued for cash upon exercise of options	200	2	623	-			-	625
Reclassification of unearned compensation upon adoption of SFAS 123R	-	-	(1,382)	-		1,382	-	-
Issuance and amortization of unearned compensation	153	1	766	-		-	-	767
Compensation on options vested	-	-	2,003	-		-	-	2,003
Balance, December 31, 2005	47,825	478	333,054	(4,997)		-	(8,080)	320,455
Comprehensive income:								
Net loss	-	-	-	-	$ 435		435	435
Other comprehensive income transactions, net of tax								
Hedging loss reclassified to income upon settlement, net of tax benefit of $1,738	-	-	-	2,860	2,860		-	2,860
Change in fair value of derivative hedging instruments, net of tax expense of $4,315	-	-	-	7,002	7,002		-	7,002
Comprehensive income					$ 10,297			
Shares issued for acquisition of Castle and oil and gas properties	2,473	25	47,307	-			-	47,332
Shares issued for cash, net of offering costs	1,500	15	33,855	-			-	33,870
Shares issued for drilling rig assets	350	3	8,291	-			-	8,294
Shares issued for cash or return of shares upon exercise of options or vesting of restricted stock	779	8	3,095	-			-	3,103
Issuance and amortization of non-vested stock	512	5	3,430	-		-	-	3,435
Compensation on options vested	-	-	1,447	-		-	-	1,447
Balance, December 31, 2006	53,439	534	430,479	4,865		-	(7,645)	428,233
Comprehensive income:								
Net loss	-	-	-	-	$ (149,347)		(149,347)	(149,347)
Other comprehensive income transactions, net of tax								
Hedging gains reclassified to income upon settlement	-	-	-	(13,920)	(13,920)		-	(13,920)
Change in fair value of derivative hedging instruments,	-	-	-	6,025	6,025		-	6,025
Tax effect of valuation allowance	-	-	-	3,030	3,030		-	3,030
Comprehensive loss					$ (154,212)			
Shares issued for oil and gas properties	1,229	12	23,753	-			-	23,765
Shares issued for cash, net of offering costs	9,898	99	196,435	-			-	196,534
Shares issued for cash or return of shares upon exercise of options or vesting of restricted stock	155	3	137	-			-	140
Issuance and amortization of non-vested stock	1,708	16	13,610	-		-	-	13,626
Compensation on options vested	-	-	319	-		-	-	319
Balance, December 31, 2007	66,429	$ 664	$ 664,733	$ -		$ -	$(156,992)	$508,405

See accompanying notes to consolidated financial statements.

DELTA PETROLEUM CORPORATION
AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2007	Years Ended December 31, 2006	Six Months Ended December 31, 2005	Year Ended June 30, 2005
	(In thousands)			
Cash flows from operating activities:				
Net Income (loss)	$ (149,347)	$ 435	$ (590)	$ 15,050
Adjustments to reconcile net income (loss) to cash provided by operating activities:				
Depreciation, depletion, and amortization – oil and gas	63,054	53,783	12,315	13,802
Depreciation and amortization – drilling and trucking	22,052	16,404	2,847	1,525
Depreciation, depletion, and amortization – discontinued operations	12,990	12,212	5,257	7,835
Accretion of abandonment obligation	319	197	96	253
Stock option and non-vested stock compensation	15,590	4,882	2,770	672
Amortization of deferred financing costs	4,429	2,396	669	858
Unrealized (gain) loss on derivative contracts	5,816	(12,205)	9,872	330
Dry hole costs and impairment	84,091	11,897	1,872	-
Minority Interest	(1,231)	2,595	688	(1,017)
Gain on sale of oil and gas properties	-	(20,034)	-	-
Gain on sale of marketable securities	-	-	(1,194)	-
Gain on sale of investment in LNG	-	(1,058)	-	-
Loss (Gain) on sale of discontinued operations	2,644	(10,775)	(11,788)	-
Extraordinary gain on Castle acquisition	-	(8,776)	-	-
DHS stock granted to management	245	280	140	-
Deferred income tax expense (benefit)	4,113	(502)	(7,336)	(3,045)
Other gain (loss)	141	319	-	394
Net changes in operating assets and liabilities:				
Increase in trade accounts receivable	(4,316)	(4,501)	(10,454)	(1,586)
(Increase) decrease in prepaid assets	441	(731)	(457)	(1,844)
(Increase) decrease in inventory	(1,385)	434	947	(5,062)
(Increase) decrease in other current assets	713	(438)	(1,968)	(225)
Increase in accounts payable trade	23,838	4,477	6,688	14,004
Increase in other accrued liabilities	195	2,095	14,505	2,918
Net cash provided by operating activities	84,392	53,386	24,879	44,862
Cash flows from investing activities:				
Additions to property and equipment,	(332,450)	(218,761)	(157,519)	(186,669)
Additions to drilling and trucking equipment,	(22,292)	(63,848)	(21,828)	(30,797)
Acquisitions, net of cash acquired	(4,500)	(8,564)	(3,905)	-
Proceeds from sale of oil and gas properties	46,193	82,716	34,178	18,721
Proceeds from sale of drilling assets	7,145	-	-	-
Proceeds from sale of marketable securities	-	-	1,764	-
Increase in marketable securities	(6,219)	-	-	-
Investment in unconsolidated affiliates	(3,929)	-	-	-
Loan to affiliate	(8,511)	-	-	-
Minority interest holder contributions (distributions)	(355)	9,018	-	14,800
(Increase) decrease in long term assets	(106)	(3,646)	802	63
Net cash used in investing activities	(325,024)	(203,085)	(146,508)	(183,882)
Cash flows from financing activities:				
Stock issued for cash upon exercise of options	137	3,711	1,166	132
Stock issued for cash, net	202,084	33,870	95,026	-
Proceeds from borrowings	343,600	220,035	72,998	361,016
Payment of financing fees	(4,897)	(3,994)	(502)	(7,370)
Repayment of borrowings	(297,867)	(101,776)	(43,781)	(214,595)
Net cash provided by financing activities	243,057	151,846	124,907	139,183
Net increase in cash and cash equivalents	2,425	2,147	3,278	163
Cash at beginning of period	7,666	5,519	2,241	2,078
Cash at end of period	$ 10,091	$ 7,666	$ 5,519	$ 2,241
Supplemental cash flow information:				
Cash paid for interest and financing costs	$ 13,926	$ 28,438	$ 8,149	$ 11,420
Non-cash financing activities:				
Common stock issued for the purchase of Castle and oil and gas properties	$ 23,765	$ 47,332	$ 828	$ 22,191
Common stock issued for the purchase of drilling and trucking equipment	$ -	$ 8,294	$ -	$ 1,893

See accompanying notes to consolidated financial statements.

(1) Nature of Organization

Delta Petroleum Corporation ("Delta" or the "Company") was organized December 21, 1984 as a Colorado corporation and is principally engaged in acquiring, exploring, developing and producing oil and gas properties. On January 31, 2006, the Company reincorporated in the state of Delaware. The Company's core areas of operation are the Rocky Mountain and Gulf Coast Regions, which comprise the majority of its 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 2004, 2005, and 2007 owns a 50.0% interest in DHS Drilling Company ("DHS"), an affiliated Colorado corporation that is headquartered in Casper, Wyoming. Delta representatives currently constitute a majority of the members of the Board of DHS and Delta has the right to use all of the rigs owned by DHS on a priority basis, although approximately half of the rigs are currently working for third party operators. DHS also owns 100% of Chapman Trucking which was acquired in November 2005 and which ensures DHS rig mobility. In May 2006, DHS acquired two rigs in conjunction with the acquisition of C&L Drilling Company, Inc. ("C&L Drilling"). Also, during the second quarter of 2006, DHS engaged in a reorganization transaction pursuant to which it became a subsidiary of DHS Holding Company, a Delaware corporation, and the Company's ownership interest became an interest in DHS Holding Company. References to DHS herein shall be deemed to include both DHS Holding Company and DHS, unless the context otherwise requires. DHS is a consolidated entity of Delta.

At December 31, 2007, the Company owned 4,277,977 shares of the common stock of Amber Resources Company of Colorado ("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.

In late 2005, the Company transferred its ownership in approximately 64,000 net acres of non-operated interests in the Columbia River Basin to CRB Partners, LLC, which originally was a wholly-owned subsidiary ("CRBP"). These interests consist of the Company's 1% overriding royalty interest convertible into a 15% back-in working interest after project payout. During the first quarter of 2006, the Company sold a 44% minority interest in CRBP. Delta has retained the majority ownership in, and is the manager of, CRBP. The non-Delta members of CRBP have certain limited consent rights with respect to, among other things, CRBP's election to convert to a working interest prior to actual project payout, disposition of its assets or effecting certain transactions outside the ordinary course of CRBP's business. Further, Delta's ownership in CRBP is subject to certain rights of first refusal and co-sale rights. The sole asset of CRBP is oil and gas properties contributed by Delta, and therefore, the sale of the minority interest in CRBP was accounted for as a disposal of oil and gas properties.

In March 2006, the Company sold approximately 26% of PGR Partners, LLC ("PGR"). PGR owns a 25% non-operated working interest in 6,314 gross acres in the Piceance Basin. The assets included in the sale consisted of both proved and unproved properties. The Company retained a 74% interest in, and is the manager of, PGR. The non-Delta members of PGR have certain limited consent rights with respect to, among other things, amending the joint operating agreement to which PGR is subject, disposition of its assets or effecting certain transactions outside the ordinary course of PGR's business.

(1) Nature of Organization, Continued

On April 28, 2006, Castle Energy Corporation shareholders approved the merger agreement between Delta and Castle Energy Corporation and subsidiaries (collectively, "Castle"). As of that date, Delta, via its merger subsidiary DPCA LLC ("DPCA"), acquired Castle. On August 21, 2006, the Company sold the Pennsylvania and West Virginia properties acquired with the Castle merger. DPCA now holds only minor non-oil and gas property assets of Castle. See Footnote 3 ("Oil and Gas Properties").

(2) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of Delta, Amber Resources Company of Colorado ("Amber"), Piper Petroleum Company ("Piper"), CRB Partners, LLC ("CRBP"), PGR Partners, LLC ("PGR"), DHS Holding Company and DHS Drilling Company (collectively "DHS"), DPCA LLC ("DPCA") and other subsidiaries with minimal net assets or activity (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 presented. The Company does not have any off-balance sheet financing arrangements (other than operating leases) or any unconsolidated special purpose entities.

During June 2007, the Company acquired a 50% non-controlling ownership interest in Delta Oilfield Tank Company, LLC ("Delta Oilfield") for cash consideration of $4.0 million. Delta Oilfield is accounted for using the equity method of accounting and is an unconsolidated affiliate of the Company. In conjunction with the investment, the Company entered into an agreement to finance up to $9.0 million for construction of a plant expansion. As of December 31, 2007, the Company had advanced $8.5 million to Delta Oilfield under this agreement, of which $7.5 million is included in other current assets in the accompanying consolidated balance sheets. The loan is payable quarterly, beginning after the expansion is complete, in an amount equal to 75% of distributable cash of Delta Oilfield, as defined, with any remaining balance due December 31, 2010.

Certain of the Company's oil and gas activities are conducted through partnerships and joint ventures, including CRBP and PGR. The Company includes its proportionate share of assets, liabilities, revenues and expenses from these entities in its consolidated financial statements.

Certain reclassifications have been made to amounts reported in previous years to conform to the current year presentation. Among other items, revenues and expenses on properties that were sold during the year ended December 31, 2007 have been reclassified to income from discontinued operations for all periods presented. Such reclassifications had no effect on net income.

Fiscal Year Change

On September 14, 2005, the Board of Directors approved the change of the fiscal year end from June 30 to December 31, effective December 31, 2005. This Form 10-K includes information for the years ended December 31, 2007 and 2006, six-month transitional period ended December 31, 2005 and for the twelve-month period ended June 30, 2005. The unaudited financial information for the twelve months ended December 31, 2005 is as follows:

(2) Summary of Significant Accounting Policies, Continued

	Twelve Months Ended December 31, 2005 (In thousands, except per share data)
Total Revenues	$ 84,818
Operating Loss	(7,007)
Loss from continuing operations before income taxes and discontinued operations	(35,533)
Net Income	5,706
Net income per common share:	
Basic	$ .13
Diluted	$ .13

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.

Marketable Securities

For the six months ended December 31, 2005 and the year ended June 30, 2005, the Company had investments classified as available-for-sale securities. Pursuant to Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments in Debt and Equity Securities" ("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. During the six months ended December 31, 2005, the Company sold its investments as shown below.

	Cost	Realized Gain (Loss)	Proceeds From Sale
		(In thousands)	
December 31, 2005			
Bion Environmental Technologies, Inc.	$ 152	$ (140)	$ 12
Tipperary Oil & Gas Company	418	1,334	1,752
	$ 570	$ 1,194	$ 1,764

	Cost	Unrealized Gain (Loss)	Estimated Market Value
		(In thousands)	
June 30, 2005			
Bion Environmental Technologies, Inc.	$ 152	$ (140)	$ 12
Tipperary Oil & Gas Company	418	1,334	1,752
	$ 570	$ 1,194	$ 1,764

During 2007, the Company held investments in securities that were classified as trading securities and thus recorded at estimated fair market value with interest, dividend income, and changes in market value recognized in earnings. The Company recorded $334,000 of losses related to these securities during the year ended December 31, 2007. Due to the marketplace changes in late 2007 affecting the liquidity of such investments, the Company reclassified the securities from trading to available for sale as of December 31, 2007. Accordingly, the marketable securities are recorded in long term assets in the accompanying consolidated balance sheet and future changes in their fair market value will be recorded in accumulated other comprehensive income until the securities are sold. If issuers of the securities we hold are unable to successfully close future auctions and their credit ratings deteriorate, we may in future periods be required to record an impairment charge to earnings on these investments.

(2) Summary of Significant Accounting Policies, Continued

Oil and Gas Properties Held for Sale

Oil and Gas Properties held for sale as of December 31, 2007 represent the Company's Texas Midway Loop oil and gas properties that are for sale. Accordingly, current and prior years' operating revenue and expense have been reclassified as a component of discontinued operations.

Oil and Gas Properties held for sale as of December 31, 2006 represent the Company's Kansas oil and gas properties that were sold in January 2007 and the Midway Loop assets mentioned above which were reclassified to conform to current presentation.

Inventories

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

Investment in LNG project

On March 30, 2006, the Company sold its long-term minority investment in a liquid natural gas ("LNG") project for total proceeds of $2.1 million. The Company recorded a gain on sale of $1.1 million ($657,000 net of tax).

Minority Interest

Minority interest represents the 50.0% (47% for Chesapeake Energy Corporation and 3.0% for DHS executive officers and management) investors of DHS at December 31, 2007. Minority interest for December 31, 2006, represents 50.6% (45% for Chesapeake Energy Corporation and 5.6% for DHS executive officers and management) investors of DHS at December 31, 2006. During 2007, one of the founding officers was bought out, resulting in a slight increase in Delta's ownership of DHS.

Investment in and Earnings (Losses) From Unconsolidated Affiliates

Investments in operating entities where the Company has the ability to exert significant influence, but does not control the operating and financial policies, are accounted for using the equity method and include the Company's 50% investment in Delta Oilfield and other minor investments. The Company's share of net income of these entities is recorded as earnings (losses) from unconsolidated affiliates in the consolidated statements of operations. Investments in operating entities where the Company does not exert significant influence are accounted for using the cost method, and income is only recognized when a distribution is received. These investments in unconsolidated affiliates are carried as a single amount in our consolidated balance sheets totaling $10.3 million and $2.9 million as of December 31, 2007 and December 31, 2006, respectively.

Revenue Recognition

Oil and Gas

Revenues are recognized when title to the products transfers 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 the year ended December 31, 2007 and 2006, six months ended December 31, 2005 and the year ended June 30, 2005, 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 was collected during the six months ended December 31, 2005.

(2) Summary of Significant Accounting Policies, Continued

Drilling and Trucking

The Company earns its contract drilling revenues under daywork or turnkey contracts. The Company recognizes revenues on daywork contracts for the days completed based on the dayrate each contract specifies. Turnkey contracts are accounted for on a percentage-of-completion basis. The costs of drilling the Company's own oil and gas properties are capitalized in oil and gas properties as the expenditures are incurred. Trucking and hauling revenues are recognized based on either an hourly rate or a fixed fee per mile depending on the type of vehicle, the services performed, and the contract terms.

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 or 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 until all costs have been recovered.

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.

Drilling equipment is recorded at cost or estimated fair value upon acquisition and depreciated on a component basis using the straight-line method over their estimated useful lives ranging from five to 15 years. Pipelines and gathering systems and other property and equipment are recorded at cost and depreciated using the straight-line method over their estimated useful lives ranging from three to 40 years.

Depreciation, depletion and amortization of oil and gas property and equipment for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and the fiscal year ended June 30, 2005 were $63.4 million, $54.0 million, $12.4 million, and $14.1 million, respectively.

Impairment of Long-Lived Assets

Statement of Financial Accounting Standards No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 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 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 six months ended December 31, 2005 and the fiscal year ended June 30, 2005. During the year ended December 31, 2007, an impairment of $58.4 million was recorded primarily related to the Howard Ranch and Fuller fields in Wyoming ($37.5 million and $10.3 million, respectively), and the South Angleton field in Texas ($9.7 million), primarily due to lower Rocky Mountain natural gas prices and marginally economic deep zones on the Howard Ranch Prospect. During the year ended December 31, 2006, an impairment of $10.4 million was recorded on certain of the Company's eastern Colorado properties primarily due to lower Rocky Mountain natural gas prices in the latter part of the year. In addition, during 2006, an impairment of $1.0 million was recorded on certain Oklahoma properties that were held for sale at December 31, 2007.

For undeveloped properties, the need for an impairment 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 December 31, 2007 and 2006, and June 30, 2005.

However, during the six months ended December 31, 2005, a dry hole was drilled on the Company's prospect located in Orange County, California. Based on drilling results and the Company's evaluation of the prospect, the Company determined that it would not pursue development of the field and accordingly an impairment was recorded. Included in the Company's consolidated statement of operations for the six months ended December 31, 2005 are $2.0 million for the dry hole that was drilled and $1.3 million for the full impairment of the remaining leasehold costs related to the prospect.

For the fiscal year 2008, the Company is continuing to develop and evaluate certain proved and unproved properties on which favorable or unfavorable results or commodity prices may cause a revision to future quarters' estimates of those properties' future cash flows. Such revisions of estimates could require the Company to record an impairment in the period of such revisions.

Goodwill

Goodwill represents the excess of the cost of the acquisitions by DHS of C&L Drilling in May 2006, Rooster Drilling in March 2006, and Chapman Trucking in November 2005 over the fair value of the assets and liabilities acquired. For goodwill and intangible assets recorded in the financial statements, an impairment test is performed at least annually in accordance with the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets," ("SFAS 142"). No impairment of goodwill was indicated as a result of the Company's impairment test performed during the third quarter of 2007.

(2) Summary of Significant Accounting Policies, Continued

Asset Retirement Obligations

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 December 31, 2007 and 2006, six months ended December 31, 2005 and fiscal year ended June 30, 2005:

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
	(In thousands)			
Asset retirement obligation – beginning of period	$ 4,421	$ 3,467	$ 3,691	$ 2,647
Accretion expense	278	199	96	253
Change in estimate	313	639	(19)	-
Obligations acquired	1,743	850	160	1,153
Obligations settled	(224)	(139)	-	-
Obligations on sold properties	(1,332)	(595)	(461)	(362)
Asset retirement obligation – end of period	5,199	4,421	3,467	3,691
Less: Current asset retirement obligation	(1,045)	(408)	(465)	(716)
Long-term asset retirement obligation	$ 4,154	$ 4,013	$ 3,002	$ 2,975

In March 2005, the FASB issued FASB Interpretation 47 ("FIN 47"), an interpretation of SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). FIN 47 clarifies the term "conditional asset retirement obligation" as it is used in SFAS 143. The Company applied the guidance of FIN 47 beginning July 1, 2005 resulting in no impact on its financial statements.

Comprehensive Income (Loss)

Comprehensive income (loss) includes all changes in equity during a period except those resulting from investments by owners and distributions to owners, if any. The components of comprehensive income (loss) for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and fiscal year ended June 30, 2005 are as follows (in thousands):

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
Net income (loss)	$(149,347)	$ 435	$ (590)	$ 15,050
Other comprehensive income (transactions):				
Realized gain on equity securities sold, net of tax benefit of $458	-	-	(736)	-
Unrealized gain on marketable securities, net of tax expense of zero, zero, zero and $458, respectively	-	-	-	394
Hedging instruments reclassified to income upon settlement, net of tax benefit of zero, $1,738 and $1,733, respectively	(13,920)	2,860	2,398	-
Change in fair value of derivative hedging instruments, net of tax (expense) benefit of zero, ($4,315), $1,036, and $3,722, respectively	6,025	7,002	(1,434)	(5,961)
Tax effect of valuation allowance	3,030	-	-	-
Comprehensive income (loss)	$(154,212)	$ 10,297	$ (362)	$ 9,483

(2) Summary of Significant Accounting Policies, Continued

Financial Instruments

The Company's financial instruments that are exposed to concentrations of credit risk consist primarily of cash equivalents, marketable securities 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.

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 marketable securities and the fair value of long-term debt were estimated based on quoted market prices. The fair values of derivative instruments were estimated based on discounted future net cash flows.

Accounting and reporting standards require 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. Those standards also require 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. The Company had no such qualifying hedge instruments at December 31, 2007.

Stock Option Plans

Prior to July 1, 2005, the Company accounted 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 2004, SFAS No. 123 (Revised 2004), "Share Based Payment" ("SFAS 123R") was issued, which now requires the Company to recognize the grant-date fair value of stock options and other equity based compensation issued to employees, in the statement of operations. The cost of share based payments is recognized over the period the employee provides service. The Company adopted SFAS 123R effective July 1, 2005 using the modified prospective method and recognized compensation expense related to stock options of $319,000, $1.4 million and $2.0 million, relating to employee provided services during the years ended December 31, 2007 and 2006 and six months ended December 31, 2005, respectively.

Non-Qualified Stock Options - Directors and Employees

On December 14, 2004, the stockholders ratified the Company's 2004 Incentive Plan (the "2004 Plan") under which it reserved up to an additional 1,650,000 shares of common stock for issuance. Although grants of shares of common stock were made under the 2004 Plan during the 2006 fiscal year, no stock options were issued by the Company during that period.

(2) Summary of Significant Accounting Policies, Continued

On January 29, 2007, the stockholders ratified the Company's 2007 Performance and Equity Incentive Plan (the "2007 Plan"). Subject to adjustment as provided in the 2007 Plan, the number of shares of Common Stock that may be issued or transferred, plus the amount of shares of Common Stock covered by outstanding awards granted under the 2007 Plan, may not in the aggregate exceed 2,800,000. The 2007 Plan supplements the Company's 1993, 2001 and 2004 Incentive Plans. The purpose of the 2007 Plan is to provide incentives to selected employees and directors of the Company and its subsidiaries, and selected non-employee consultants and advisors to the Company and its subsidiaries, who contribute and are expected to contribute to the Company's success and to create stockholder value.

Incentive awards under the 2007 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.

Exercise prices for options outstanding under the Company's various plans as of December 31, 2007 ranged from $1.75 to $15.60 per share, and the weighted-average remaining contractual life of those options was 4.18 years. All compensation expense related to these options has been recorded as of December 31, 2007. The Company has not issued stock options since the adoption of SFAS 123R, though it has the discretion to issue options again in the future. At December 31, 2007, all remaining options outstanding were fully vested.

Had compensation cost for the Company's stock-based compensation plan been determined using the fair value of the options at the grant date prior to July 1, 2005, the Company's net income for the year ended June 30, 2005 would have been as follows:

	Year Ended June 30, 2005 (In thousands, except per share amounts)
Net income (loss)	$ 15,050
Equity compensation booked	306
FAS 123 compensation effect	(2,759) [1]
Pro forma net income after FAS 123 implementation	$ 12,597
Pro forma income per common share:	
Basic	$ .31
Diluted	$ .30

1 During the quarter ended December 31, 2004, the Company granted 420,000 options to officers and 98,000 options to directors to purchase shares of its common stock at an average price of $15.34 per share, which was the market price on the date of the grant. The officers' options vest over a three year period and the directors' options vested on March 15, 2005. The fair market value of each option granted was $10.07 and was calculated using a risk free rate of 4.60%, volatility factors of the expected market price of the Company's common stock of 48.76% and an average expected life of 8.0 years. During the quarter ended December 31, 2004, the Company granted 318,000 options to employees to purchase 318,000 shares of its common stock at an average price of $15.29 per share. Certain options were granted below market price. For options granted below market price, the Company recorded an expense for the difference between the option price and the grant price. The employee options vested over a year period. The average fair market value of each option granted was $7.10 and was calculated using a risk free rate of 4.60%, volatility factors of the expected market price of the Company's common stock of 48.76% and an average expected life of 3.2 years. During the quarter ended March 31, 2005, the Company granted 105,700 options to employees to purchase 105,700 shares of its common stock at an average price of $14.75 per share. The employee options vested over a year period. The average fair market value of each option granted was $7.49 and was calculated using a risk free rate of 4.65%, volatility factors of the expected market price of the Company's common stock of 61.23% and an average expected life of 2.0 years. The SFAS 123R compensation effect is calculated based on the options' vesting period and includes additional grants from other periods.

On February 9, 2007, the Company issued executive performance share grants to each of the Company's four executive officers (Roger Parker - Chief Executive Officer, John Wallace - President, Kevin Nanke - Chief Financial Officer, and Ted Freedman - Senior Vice President and General Counsel) that provide that the shares of common stock awarded will vest if the market price of Delta stock reaches and maintains certain price levels. The awards will vest in five tranches on the dates that the average daily closing price of Delta's common stock equals or exceeds a defined price for a specified number of trading days within any period of 90 calendar days (a "Vesting Threshold"). The Vesting Threshold for the first tranche is $40, for the second tranche it is $50, for the third tranche it is $60, for the fourth tranche it is $75 and for the fifth tranche it is $90. Upon attaining the Vesting Threshold for each of the

(2) Summary of Significant Accounting Policies, Continued

first, second and third tranches, 100,000 of Mr. Parker's shares would vest for each such tranche, 70,000 of Mr. Wallace's shares would vest for each such tranche and 40,000 of Mr. Nanke's and Mr. Freedman's shares would each vest for each such tranche. Upon attaining the Vesting Thresholds for each of the fourth and fifth tranches, 150,000 of Mr. Parker's shares would vest for each such tranche, 105,000 of Mr. Wallace's shares would vest for each such tranche and 60,000 of Mr. Nanke's and Mr. Freedman's shares would each vest for each such tranche. Each award provides for the lapse of the $75 and $90 tranches if the $40 tranche has not vested on or before March 31, 2008, and the lapse of the $50 and $60 tranches if the $40 tranche has not vested on or before March 31, 2009. In addition, the grants will lapse and be forfeited to the extent not vested prior to a termination of the executive's employment, and will be forfeited to the extent not vested on or before January 29, 2017. The awards also provide for a minimum 364-day period between achievement of two vesting thresholds, subject to acceleration of vesting upon a change in control at a price in excess of one or more of the stock price thresholds, with proportional vesting should a change in control occur at a price in excess of one threshold, but below the next threshold.

The performance share grants were valued at $18.4 million, in the aggregate, with derived service periods over which the value of each tranche will be expensed ranging from 1 to 5 years. Equity compensation of $6.9 million related to the performance share grants was included in general and administrative expense during the year ended December 31, 2007.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes as set forth in SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"). 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 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. Deferred tax assets are recorded based on the "more likely than not" requirements of SFAS 109, and to the extent this threshold is not met, a valuation allowance is recorded. The Company is currently providing a full valuation allowance on its net deferred tax assets. DHS deferred tax assets and liabilities are recorded on the same basis of accounting, though no valuation allowance has been provided.

Income (Loss) per Common Share

Basic income (loss) per share is computed by dividing net income (loss) attributed to common stock by the weighted average number of common shares outstanding during each period, excluding treasury shares. Diluted income (loss) per share is computed by adjusting the average number of common shares outstanding for the dilutive effect, if any, of convertible preferred stock, convertible debt, stock options, restricted stock 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, depletion and impairment of oil and gas properties, marketable securities, income taxes, derivatives, asset retirement obligations, contingencies and litigation accruals. Actual results could differ from these estimates.

(2) Summary of Significant Accounting Policies, Continued

Recently Issued Accounting Standards and Pronouncements

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "Business Combinations" ("SFAS 141R"), which replaces SFAS 141. SFAS 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any resulting goodwill, and any noncontrolling interest in the acquiree. The Statement also provides for disclosures to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008, or fiscal year 2009, and must be applied prospectively to business combinations completed on or after that date. The Company will evaluate how the new requirements could impact the accounting for any acquisitions completed beginning in fiscal 2009 and beyond, and the potential impact on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of Accounting Research Bulletin No. 51" ("SFAS 160"), which establishes accounting and reporting standards for noncontrolling interests ("minority interests") in subsidiaries. SFAS 160 clarifies that a noncontrolling interest in a subsidiary should be accounted for as a component of equity separate from the parent's equity. SFAS 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008, or fiscal year 2009, and must be applied prospectively, except for the presentation and disclosure requirements, which will apply retrospectively. The Company is currently evaluating the potential impact of the adoption of SFAS 160 on its consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"). SFAS 159 permits companies to choose to measure many financial instruments and certain other items at fair value. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, or fiscal year 2008. The Company has not yet determined if it will elect to apply any of the provisions of SFAS 159 or what effect the adoption of the Statement would have, if any, on its consolidated financial statements.

In September 2006, the FASB issued Statement of Financial Accounting Standards No. 157, "Fair Value Measurements" ("SFAS 157"), which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and requires additional disclosures about fair value measurements. SFAS 157 aims to improve the consistency and comparability of fair value measurements by creating a single definition of fair value. The Statement emphasizes that fair value is not entity-specific, but instead is a market-based measurement of an asset or liability. SFAS 157 upholds the requirements of previously issued pronouncements concerning fair value measurements and expands the required disclosures. This Statement is effective for fiscal year commencing January 1, 2008. The Company does not expect the impact of SFAS 157 to be material to the Company's financial condition or results of operations. The Company anticipates the primary impact of the standard will be additional disclosures related to the measurement of fair value in the Company's recurring impairment test calculations related to oil and gas properties, drilling rigs, and goodwill, the valuation of oil and gas derivative instruments, and the valuation of assets acquired or liabilities assumed in future business combinations, if any.

Recently Adopted Accounting Standards and Pronouncements

Effective January 1, 2007, the Company adopted provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109" ("FIN 48"). FIN 48 provides detailed guidance for the financial statement recognition, measurement and disclosure of uncertain tax positions recognized in the financial statements in accordance with SFAS 109. Tax positions must meet a "more-likely-than-not" recognition threshold at the effective date to be recognized upon the adoption of FIN 48 and in subsequent periods. Upon the adoption of FIN 48, the Company had no unrecognized tax benefits. During the year ended December 31, 2007, no adjustments were recognized for uncertain tax benefits.

(2) Summary of Significant Accounting Policies, Continued

The Company recognizes interest and penalties related to uncertain tax positions in income tax (benefit)/expense. No interest and penalties related to uncertain tax positions were accrued at December 31, 2007.

The tax years 2003 through 2007 for federal returns and 2002 through 2007 for state returns remain open to examination by the major taxing jurisdictions in which we operate, although no material changes to unrecognized tax positions are expected within the next twelve months.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin No. 108 ("SAB 108"). SAB 108 was issued to provide interpretive guidance on how the effects of the carryover reversal of prior year misstatements should be considered in quantifying a current year misstatement. The provisions of SAB 108 were effective for the December 31, 2006 year-end. The adoption of SAB 108 had no impact on our financial position or results of operations.

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" ("SFAS 154"). SFAS 154 requires retrospective application to prior periods' financial statements for changes in accounting principles, 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 SFAS 154 did not have a material impact on the Company's consolidated results of operations, financial position or cash flows.

In April 2005, the FASB issued Staff Position 19-1, "Accounting for Suspended Well Costs" ("FSP 19-1"). FSP 19-1 provides guidance for evaluating whether sufficient progress is being made to determine whether reserves can be classified as proved and 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. FSP 19-1 is effective for all reporting periods beginning after April 4, 2005, and accordingly, the Company adopted FSP 19-1 on July 1, 2005. The following table reflects the net changes in capitalized exploratory well costs for the periods presented below:

	Years Ended December 31, 2007	Years Ended December 31, 2006	Six Months Ended December 31, 2005	Year Ended June 30, 2005
Balance at beginning of period	$ 27,453	$ 357	$ 1,033	$ 10
Additions to capitalized exploratory well costs pending the determination of proved reserves[1]	30,797	27,744	10,151	10,991
Exploratory well costs included in property divestitures	(2,941)	-	-	-
Reclassified to proved oil and gas properties based on the determination of proved reserves	-	(357)	(6,754)	(7,197)
Capitalized exploratory well costs charged to dry hole expense	(11,218)	(291)	(4,073)	(2,771)
Balance at end of period	$ 44,091	$ 27,453	$ 357	$ 1,033
Exploratory well costs capitalized for one year or less	35,649	27,453	357	1,033
Exploratory well costs capitalized for greater than one year after completion of drilling	8,442	-	-	-
Balance at end of period	$ 44,091	$ 27,453	$ 357	$ 1,033

[1] The final FSP directs that costs suspended and expensed in the same period not be included in this analysis.
[2] Capitalized exploratory well costs for fiscal years ended June 30, 2005 are presented based on the Company's previous accounting policy.

Included in capitalized exploratory well costs capitalized for greater than one year at December 31, 2007 were two projects. One project representing $1.7 million of the costs is non-operated and pending connection to a new field gathering system. During 2007, permitting for the infrastructure was obtained and construction began. The second project representing $6.8 million of the costs is related to the Company's Paradox Basin properties. In early 2008, permitting was obtained and construction began for the necessary pipeline infrastructure.

(3) Oil and Gas Properties

Unproved Undeveloped Offshore California Properties

The Company has direct and indirect ownership interests ranging from 2.49% to 100% in five unproved undeveloped offshore California oil and gas properties with aggregate carrying values of $14.8 million and $12.5 million at December 31, 2007 and 2006, 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. The recovery of the Company's investment in these properties through the sale of hydrocarbons will require extensive exploration and development activities (and costs) that cannot proceed without certain regulatory approvals that have been delayed, and is therefore subject to other substantial risks and uncertainties.

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 would proceed with exploration and development plans under the terms and conditions of the operating agreement if they were permitted to do so by regulators.

Based on indications of levels of hydrocarbons present from drilling operations conducted in the past, the Company believes the fair values of its property interests are in excess of their carrying values at December 31, 2007, 2006 and 2005 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 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 will 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.

In 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. In response to the ruling in the Norton case, the MMS made a consistency determination under the CZMA and the leases are still valid.

Further actions to develop the leases have been delayed, however, pending the outcome of a separate lawsuit (the "Amber case") that was filed in the United States Court of Federal Claims (the "Court") in Washington, D.C. by the Company, its 92%-owned subsidiary, Amber Resources Company of Colorado, and ten other property owners alleging that the U.S. government materially breached the terms of forty undeveloped federal leases, some of which are part of the Company's and Amber's offshore California properties. On November 15, 2005 and October 31, 2006, the Court granted summary judgment as to liability and partial summary judgment as to damages with respect to thirty six of the forty total federal leases that are the subject of the litigation. Under a restitution theory of damages, the Court ruled that the government must give back to the current lessees the more than $1.1 billion in lease bonuses

(3) Oil and Gas Properties, Continued

it had received at the time of sale. On January 19, 2006, the government filed a motion for reconsideration of the Court's ruling as it relates to a single lease owned entirely by the Company ("Lease 452"). In its motion for reconsideration, the government has asserted that the Company should not be able to recover lease bonus payments for Lease 452 because, allegedly, a significant portion of the hydrocarbons has been drained by wells that were drilled on an immediately adjacent lease. The amount of lease bonus payments attributable to Lease 452 is approximately $92.0 million. A trial on the motion for reconsideration was completed in January 2008 and post-trial briefing is currently in process. The Company believes that the government's assertion is without merit, but it cannot predict with certainty the ultimate outcome of this matter.

On January 12, 2007, the Court entered an order of final judgment awarding the lessees restitution of the original lease bonuses paid for thirty five of the forty lawsuit leases. Under this order the Company is entitled to receive a gross amount of approximately $58.5 million and Amber is entitled to receive a gross amount of approximately $1.5 million as reimbursement for the lease bonuses paid for all lawsuit leases other than Lease 452. The government has appealed the order and contends that, among other things, the Court erred in finding that it breached the leases, and in allowing the current lessees to stand in the shoes of their predecessors for the purposes of determining the amount of damages that they are entitled to receive. The current lessees are also appealing the order of final judgment to, among other things, challenge the Court's rulings that they cannot recover their and their predecessors' sunk costs as part of their restitution claim. No payments will be made until all appeals have either been waived or exhausted. In the event that the Company ultimately receives any proceeds as the result of this litigation, it will be obligated to pay a portion to landowners and other owners of royalties and similar interests, to pay the litigation expenses and to fulfill certain pre-existing contractual commitments to third parties.

If new activities are commenced on the any of the leases, the requisite exploration and development plans will be subject to review by the California Coastal Commission for consistency with the CZMA and by the MMS for other technical requirements. None of the leases is currently impaired, but in the event that they are found not to be valid for some reason in the future, it would appear that they would become impaired. For example, if there is a 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. 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.

Year Ended December 31, 2007 – Acquisitions

On October 1, 2007, the Company completed a transaction involving an exchange of Washington County, Colorado properties and cash consideration of $33.0 million, prior to customary purchase price adjustments, to acquire a 12.5% working interest in the Garden Gulch field in the Piceance Basin. The transaction was accounted for as a non-monetary transaction in relation to the exchange of assets with a nominal loss recorded on the divestiture of the Washington County assets equal to the fair value of the asset relinquished less its net book value. The acquisition basis of the Garden Gulch asset acquired was recorded equal to the fair value of the Washington County assets relinquished plus the additional cash consideration paid.

On June 8, 2007, the Company issued 475,000 shares of common stock valued at approximately $9.9 million using a 5-day average closing price to acquire an additional interest in one well already owned and operated by the Company, and an additional interest in a non-operated property, both located in Polk County, Texas.

On March 9, 2007, the Company issued 754,000 shares of common stock valued at approximately $13.8 million using a 5-day average closing price for additional interests in two wells already owned and operated by the Company located in Polk County, Texas.

(3) Oil and Gas Properties, Continued

On March 1, 2007, the Company paid $3.5 million for interests in producing properties and 39,000 undeveloped net acres in Fremont County, Wyoming.

In March 2007, the Company executed an earn-in agreement with EnCana whereby the Company can earn up to 6,000 net acres in the Piceance Basin with the drilling of 128 wells during the next 36 months. The Company is committed to drill 64 total wells, eight of which were drilled by October 31, 2007. The remaining wells are required to be drilled by June 1, 2009. The Company is liable for $250,000 per undrilled well in the event the drilling obligations are not met.

Year Ended December 31, 2006 – Acquisitions

On April 28, 2006, Castle shareholders approved the merger agreement between Delta and Castle. As of that date, Delta via its merger subsidiary DPCA, acquired Castle for a purchase price of $33.6 million comprised of 1.8 million net shares issued (8,500,000 shares issued net of 6,700,000 Delta shares owned by Castle) valued at $31.2 million and $2.4 million of transaction costs. Delta obtained assets valued at $39.7 million which were comprised of cash, producing oil and gas properties located in Pennsylvania and West Virginia, and certain other assets. Due to the excess fair value of the assets acquired compared to the purchase price of the transaction and in accordance with SFAS No. 141 when acquired assets are held for sale in the near term, Delta recorded a $6.1 million extraordinary gain ($9.6 million, net of $3.5 million of deferred taxes) during the quarter ended June 30, 2006. The properties were actually sold during August 2006 and a true-up of the gain based on actual final proceeds from the sale was recorded. No pro forma information is presented because discontinued operations are not reported in revenue and earnings from continuing operations, and the information related to the acquisition would be the same as the amounts reported.

On February 1, 2006 Delta entered into a purchase and sale agreement with Armstrong Resources, LLC ("Armstrong") to acquire a 65% working interest in approximately 88,000 undeveloped gross acres in the central Utah hingeline play for a purchase price of $24 million in cash and 673,401 shares of common stock valued at $16.1 million. The closing of the transaction was effective as of January 26, 2006. Armstrong retained the remaining 35% working interest in the acreage. As part of the transaction, Delta agreed to pay 100% of the drilling costs for the first three wells in the project. Delta will be the operator of the majority of the acreage, and drilling of the first well commenced in November 2006.

Six Months Ended December 31, 2005 – Acquisitions

On September 29, 2005 the Company acquired an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington, and an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant Resources, LLC ("Savant") for an aggregate purchase price of $85.0 million in cash. 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 consolidated the Company's leasehold position at that time. Subsequent to the acquisition, Delta owned a 100% working interest in approximately 385,000 net acres. This acquisition included a small portion of acreage that is subject to an agreement with EnCana Oil & Gas (USA) Inc., whereby the Company has the right to convert an overriding royalty interest to a working interest at project payout. In the Piceance Basin, the Company acquired Savant's interest in an entity that owns a 25% interest in approximately 6,314 gross acres that is currently being developed. The acquisition was funded through the issuance of securities discussed in Footnote 6, "Stockholders' Equity."

(3) Oil and Gas Properties, Continued

Fiscal 2005 – Acquisitions

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.

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. Substantially all of the assets that were acquired from Manti have been pledged as collateral on the Company's bank credit facility.

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% stockholder, 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.

Fiscal 2006 – Dispositions

During December 2005, Delta transferred its ownership in approximately 427,000 gross acres (64,000 net acres) of non-operated interests in the Columbia River Basin to CRBP. In January and March 2006, Delta sold a combined 44% minority interest in CRBP. As the sale involved unproved properties, no gain on the partial sale of CRBP could be recognized until all of the cost basis of CRBP had been recovered. Accordingly, the Company recorded a $13.0 million gain ($8.1 million net of tax) and an $11.2 million reduction to property during the first quarter of 2006 as a result of closing the transaction.

In March 2006, the Company sold approximately 26% of PGR. This transaction involved both proved and unproved property interests and accordingly, to the extent the sale of PGR related to unproved properties, no gain could be recognized as all of the unproved cost basis was not yet recovered. The Company recorded a gain of $5.9 million, $3.7 million net of tax, and a $3.4 million offset to property during the first quarter of 2006 as a result of the transaction. The Company retains a 74% interest in PGR.

Six Months Ended December 31, 2005 – Dispositions

During October 2005, the Company sold its interest in various insignificant fields that were not strategic to the Company for proceeds of $5.3 million. The Company recorded a gain of $1.6 million, net of a $1.0 million provision for income taxes.

(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. Also included in discontinued operations are the Company's Midway Loop, Texas oil and gas properties which are held for sale at December 31, 2007.

On October 1, 2007, the Company completed a transaction involving an exchange of Washington County, Colorado properties and cash consideration of $33.0 million, prior to customary purchase price adjustments, to acquire a 12.5% working interest in the Garden Gulch field in the Piceance Basin.

On September 4, 2007, the Company completed the sale of certain non-core properties located in North Dakota for cash consideration of approximately $6.2 million. The transaction resulted in a gain on sale of properties of $4.3 million.

On March 30, 2007, the Company completed the sale of certain non-core properties located in New Mexico and East Texas for cash consideration of approximately $31.5 million, prior to customary purchase price adjustments. The sale resulted in a loss of approximately $10.8 million.

On March 27, 2007, the Company completed the sale of certain non-core properties located in Australia for cash consideration of approximately $6.0 million. The sale resulted in an after-tax gain of $2.0 million.

On January 10, 2007, the Company completed the sale of certain non-core properties located in Padgett field, Kansas for cash consideration of $5.6 million. The transaction resulted in a gain on sale of properties of $297,000.

On August 21, 2006, the Company completed the sale of the properties acquired with the Castle acquisition in April 2006. During the year ended December 31, 2006, the Company recorded a $5.6 million extraordinary gain in accordance with SFAS No. 141.

On August 11, 2006, the Company sold certain non-operated East Texas interests for sales proceeds of $14.6 million and a gain of $9.8 million ($6.1 million net of tax).

On June 1, 2006, the Company completed the sale of certain properties located in Pointe Coupee Parish, Louisiana, for cash consideration of $8.9 million with an effective date of May 1, 2006. The transaction resulted in an after-tax gain on sale of oil and gas properties of $596,000.

On September 2, 2005, the Company completed the sale of its Deerlick Creek field in Tuscaloosa County, Alabama for $30.0 million with an effective date of July 1, 2005. The Company recorded an after tax gain on sale of oil and gas properties of $10.2 million on net proceeds of approximately $28.9 million after normal closing adjustments.

(3) Oil and Gas Properties, Continued

The following table shows the total revenues and income included in discontinued operations for the above mentioned oil and gas properties for the years ended December 31, 2007 and 2006, the six months ended December 31, 2005, and the year ended June 30, 2005:

	Years Ended December 31, 2007	Years Ended December 31, 2006	Six Months Ended December 31, 2005	Year Ended June 30, 2005
	(In thousands)			
Revenues	$ 36,084	$ 36,956	$ 18,012	$ 38,425
Income from discontinued operations	$ 17,642	$ 14,743	$ 8,686	$ 21,630
Income tax expense	(86)	(5,580)	(2,734)	(8,196)
Income from discontinued operations, net of tax	$ 17,556	$ 9,163	$ 5,952	$ 13,434

(4) DHS Drilling Company

On April 15, 2005, the Company acquired a 49.4% ownership interest in DHS Drilling Company. The investment included the contribution of all of the net assets of the then 100% owned subsidiary, Big Dog, and certain drilling assets acquired by the Company. Previously, on March 31, 2005, the Company had purchased the remaining 50% interest of Big Dog owned by Davis for 100,000 shares of Delta's common stock valued at $1.4 million based on the closing stock price on March 31, 2005, its 50% interest in Shark, another 100% owned subsidiary, and certain drilling equipment. Delta has the right to use all of the DHS rigs on a priority basis, although approximately one-half are currently working for third party operators.

In January 2006, the Company purchased Rooster Drilling Company ("Rooster Drilling") for 350,000 shares of Delta common stock valued at $8.3 million. Rooster Drilling owned one drilling rig, an Oilwell 66 with a depth capacity of 12,000 feet. Concurrent with the Company's acquisition of Rooster Drilling, the Company and DHS entered into an operating agreement whereby DHS operated the rig ("Rig 15") on behalf of the Company. In March 2006, the Company contributed Rooster Drilling (renamed "Hastings Drilling Company") to DHS.

In March 2006, DHS issued additional common stock to Delta, Chesapeake, and officers and management of DHS in exchange for assets, cash and notes as described below. The Company contributed Rooster Drilling and additional cash totaling $9.9 million to DHS in exchange for 2.7 million shares of DHS common stock. Chesapeake contributed approximately $9.0 million in cash to DHS in exchange for 2.4 million shares of DHS common stock. Two executive officers purchased 150,000 shares each by execution and delivery of promissory notes for $549,000. An officer of DHS paid $33,000 for 9,000 shares of DHS common stock. Subsequent to these transactions there were 14.6 million shares of DHS common stock outstanding.

During the fourth quarter 2007, the Company acquired an additional interest for $354,000 from one of the DHS founding officers, increasing the Company's total ownership interest to 50.0% as of December 31, 2007.

On March 5, 2007, DHS purchased a drilling rig ("Rig 18") for cash consideration of $7.6 million, funded with borrowings under the DHS credit facility. The rig is a 700 horsepower rig with a depth rating of 10,500 feet. The rig is currently operating in the Rocky Mountain Region.

In March 2006, DHS purchased a Kremco 750G drilling rig ("Rig 16") for $4.75 million. The rig is a 500 horsepower rig with a depth rating of 10,000 feet. The rig commenced work in the Rocky Mountain Region in June 2006.

(4) DHS Drilling Company , Continued

In May 2006, DHS acquired two rigs ("Rig 12" and "Rig 14") and certain other assets in conjunction with the acquisition of C&L Drilling for a purchase price of approximately $16.7 million. Rigs 12 and 14 have depth ratings of 15,000 and 12,500 feet, respectively. The rigs are currently under contract to third party operators and working in California and Utah.

On July 18, 2006, DHS purchased a National 55 drilling rig ("Rig 17") for $7.25 million. The rig is a 1,000 horsepower rig with a depth rating of 12,500 feet. The rig was placed into service during the fourth quarter 2006 and is working in Fremont County, Wyoming.

In December 2007, DHS sold Rigs 2 and 3 for proceeds of $6.3 million and a net loss of $31,000. The proceeds from the rigs sold were used to pay-off the JP Morgan credit facility balance in conjunction with the new Lehman facility. (See Footnote 5, "Long Term Debt").

(5) Long Term Debt

7% Senior Unsecured Notes, due 2015

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 its 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, repurchase capital stock, pay dividends, make certain investments, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries. These covenants may limit the discretion of the Company's management in operating the Company's business. The Company was not in default (as defined in the indenture) under the indenture as of December 31, 2007. (See Footnote 12, "Guarantor Financial Information"). The fair value of the Company's senior notes at December 31, 2007 was $134.6 million.

3¾% Senior Convertible Notes, due 2037

On April 25, 2007, the Company issued $115.0 million aggregate principal amount of 3¾% Senior Convertible Notes due 2037 (the "Notes") for net proceeds of $111.6 million after underwriters' discounts and commissions of approximately $3.4 million. The Notes bear interest at a rate of 3¾% per annum, payable semi-annually in arrears, on May 1 and November 1 of each year, beginning November 1, 2007. The Notes will mature on May 1, 2037 unless earlier converted, redeemed or repurchased. The Notes will be convertible at the holder's option, in whole or in part, at an initial conversion rate of 32.9598 shares of common stock per $1,000 principal amount of Notes (equivalent to a conversion price of approximately $30.34 per share) at any time prior to the close of business on the business day immediately preceding the final maturity date of the Notes, subject to prior repurchase of the Notes. The conversion rate may be adjusted from time to time in certain instances. Upon conversion of a Note, the Company will have the option to deliver shares of common stock, cash or a combination of cash and shares of common stock for the Notes surrendered. In addition, following certain fundamental changes that occur prior to maturity, the Company will increase the conversion rate for a holder who elects to convert its Notes in connection with such fundamental changes by a number of additional shares of common stock. Although the Notes do not contain any financial covenants, the Notes contain covenants that require the Company to properly make payments of principal and interest, provide certain reports, certificates and notices to the trustee under various circumstances, cause its wholly-owned subsidiaries to become guarantors of the debt, maintain an office or agency where the Notes may be presented or surrendered for payment, continue its corporate existence, pay taxes and other claims, and not seek protection from the debt under any applicable usury laws. The fair value of the Notes at December 31, 2007 was approximately $110.7 million.

(5) Long Term Debt, Continued

Credit Facility

During the year ended December 31, 2007, the Company's borrowing base under its $250.0 million credit facility was $140.0 million. At December 31, 2007, the Company had $73.6 million outstanding under the facility. Borrowing availability under this credit facility at December 31, 2007 was approximately $49.9 million after reduction for the outstanding balance and $16.5 million of outstanding letters of credit. The borrowing base is redetermined semiannually and can be increased 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 LIBOR and prime rates at December 31, 2007 approximated 6.35% and 7.25%, respectively. The loan is collateralized by substantially all of the Company's oil and gas properties. The Company is required to meet certain financial covenants for the quarter ended December 31, 2007 which include a current ratio of 1 to 1, net of derivative instruments and deferred taxes, as defined, and a consolidated debt to EBITDAX (earnings before interest, taxes, depreciation, amortization and exploration) of less than 4.0 to 1 for the quarter ended December 31, 2007, and 3.75 to 1 for the end of each quarter thereafter. The financial covenants only include subsidiaries which the Company owns 100%. At December 31, 2007, the Company was in compliance with its quarterly debt covenants and restrictions under the facility. The facility matures on December 31, 2010. Subsequent to year-end, the Company paid down its borrowing base in full with proceeds from an equity offering completed in February (See Footnote 18 "Subsequent Events").

Unsecured Term Loan

In December 2006 the Company entered into an agreement with JP Morgan Chase Bank N.A., for a $25.0 million unsecured term loan with interest at LIBOR plus a margin of 3.5% at December 31, 2006. The note was paid in full in January 2007 with the proceeds from an equity offering.

Credit Facility – DHS

On December 20, 2007, DHS entered into a new $75.0 million credit agreement with Lehman Commercial Paper Inc. The proceeds were used to pay off the JP Morgan credit facility discussed below. The Lehman credit facility has a variable interest rate based on 90-day LIBOR plus a fixed margin of 5.50% which approximated 10.43% as of December 31, 2007. The note matures on December 31, 2010. Annual principal payments are based upon a calculation of excess cash flow (as defined) for the preceding year. DHS is required to meet certain financial covenants quarterly beginning March 31, 2008 including (i) consolidated EBITDA for four consecutive fiscal quarters must be greater than $20.0 million; (ii) Consolidated Leverage Ratio (as defined) for four consecutive fiscal quarters cannot exceed 3.50 to 1.00; (iii) Consolidated Interest Coverage Ratio (as defined) for four consecutive fiscal quarters must exceed 2.50 to 1.00 and (iv) the Current Ratio for any fiscal quarter must be greater than 1.0 to 1.0. DHS incurred $1.3 million of financing charges in conjunction with the agreement which will be amortized over the life of the loan.

On May 4, 2006, DHS entered a $100.0 million senior secured credit facility with JP Morgan Chase Bank, N.A. Proceeds from the $75.0 million initial draw were used to pay off the Guggenheim term loan, complete the acquisition of C&L Drilling, finance additional capital expenditures and pay transaction expenses. In December 2007, DHS used proceeds from the Lehman credit agreement and the sale of Rigs 2 and 3 to pay off the $79.7 million outstanding balance of the JP Morgan senior secured credit facility.

(5) Long Term Debt, Continued

Term Loan - DHS

On May 4, 2006, DHS used proceeds from the JP Morgan credit facility to pay off the remaining balance of the previously outstanding term loan of approximately $41.0 million and prepayment penalties of approximately $820,000. In addition, $431,000 of unamortized deferred financing costs associated with the repaid term loan were written-off during the quarter ended June 30, 2006. Borrowing availability at December 31, 2007 was zero under the DHS facility.

Maturities

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

YEAR ENDING December 31,	
2008	$ 13
2009	-
2010	148,600
2011	-
2012	-
Thereafter	265,000
	$ 413,613

(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 December 31, 2007 and 2006, no preferred stock was issued. As part of the reincorporation on January 31, 2006, the Company reduced the par value of the preferred stock to $.01 per share.

Common Stock

During the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and fiscal year ended June 30, 2005, the Company acquired oil and gas properties for 1,229,000 shares, 673,000 shares, 50,000 shares, and 1,571,000 shares of the Company's common stock, respectively. The shares were valued at $23.7 million, $16.1 million, $799,000, and $22.2 million, respectively, based on the market price of the shares at the time of issuance.

On June 8, 2007, the Company issued 475,000 shares of common stock valued at approximately $9.9 million to acquire an additional interest in one well already owned and operated by the Company, and an additional interest in a non-operated property, both located in Polk County, Texas.

On April 25, 2007, the Company received net proceeds of $140.3 million from a public offering of 7,130,000 shares of the Company's common stock.

On March 9, 2007, the Company issued 754,000 shares of common stock valued at approximately $13.8 million to acquire additional interests in two wells already owned and operated by the Company located in Polk County, Texas.

On February 9, 2007, the Company issued 1.5 million non-vested shares as executive performance share grants to the Company's four executive officers that provide that the shares of common stock awarded will vest if the market price of Delta stock reaches and maintains certain price levels (See Footnote 2, "Summary of Significant Accounting Policies").

(6) Stockholders' Equity, Continued

On January 25, 2007, the Company received net proceeds of $56.4 million from a public offering of 2,768,000 shares of the Company's common stock.

On October 2, 2006, the Company granted 334,500 shares of restricted common stock to certain non-executive employees. These shares will vest over a three year service period.

On April 28, 2006, Castle shareholders approved the merger agreement between Delta and Castle as announced on November 8, 2005. Delta, via its merger subsidiary DPCA, acquired Castle which held 6,700,000 shares of Delta, and issued 8,500,000 shares of its common stock to Castle's stockholders, for a net issuance of 1,800,000 shares of common stock. The shares of the Company's common stock were valued at $31.2 million using the average five-day closing price before and after the terms of the agreement were agreed upon and announced.

On February 1, 2006, the Company acquired a 65% working interest in approximately 88,000 gross acres in the central Utah hingeline play from Armstrong Resources, LLC for 673,401 shares and $24.0 million in cash. The shares of the Company's common stock were valued at $16.1 million using the average five-day closing price before and after the terms of the agreement were agreed upon and announced. The total purchase price of $40.1 million was allocated to unproved undeveloped properties.

On February 1, 2006, the Company received net proceeds of $33.9 million from a public offering of 1.5 million shares of the Company's common stock.

In January 2006, the Company purchased Rooster Drilling for 350,000 shares of Delta common stock valued at $8.3 million based on the value of the stock when the transaction closed (See Footnote 4 "DHS Drilling Company").

On September 27, 2005, the Company sold 5,405,418 shares of common stock to twenty-seven institutional investors at a price of $18.50 per share in cash for gross proceeds of $100.0 million and net proceeds of approximately $95.0 million. The proceeds were used to finance the Savant acquisition discussed above and to fund drilling activities.

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 December 14, 2004, the stockholders ratified the Company's 2004 Incentive Plan (the "2004 Plan") under which it reserved up to an additional 1,650,000 shares of common stock for issuance. Although grants of shares of common stock were made under the 2004 Plan during the 2006 fiscal year, no stock options were issued by the Company during that period.

On January 29, 2007, the stockholders ratified the Company's 2007 Performance and Equity Incentive Plan (the "2007 Plan"). Subject to adjustment as provided in the 2007 Plan, the number of shares of Common Stock that may be issued or transferred, plus the amount of shares of Common Stock covered by outstanding awards granted under the 2007 Plan, may not in the aggregate exceed 2,800,000. The 2007 Plan supplements the Company's 1993, 2001 and 2004 Incentive Plans. The purpose of the 2007 Plan is to provide incentives to selected employees and directors of the Company and its subsidiaries, and selected non-employee consultants and advisors to the Company and its subsidiaries, who contribute and are expected to contribute to the Company's success and to create stockholder value.

Incentive awards under the 2007 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.

(6) Stockholders' Equity, Continued

A summary of the stock option activity under the Company's various plans and related information for the year ended December 31, 2007 follows:

	Year Ended December 31, 2007			
	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding-beginning of year	2,359,776	$ 7.85		
Granted	-	-		
Exercised	(202,510)	(4.86)		
Expired / Returned	-	-		
Outstanding-end of year	2,157,266	$ 9.04	4.18	$21,153,000
Exercisable-end of year	2,157,266	$ 9.04	4.18	$21,153,000

The total intrinsic value of options exercised during the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and the year ended June 30, 2005 were $2.8 million, $12.3 million, $3.2 million, and $24.9 million, respectively.

A summary of the Company's non-vested stock options and related information for the year ended December 31, 2007 follows:

	Year Ended December 31, 2007	
	Options	Weighted-Average Grant-Date Fair Value
Nonvested-beginning of year	166,667	$ 7.67
Granted	-	-
Vested	(166,667)	(7.67)
Forfeited / Returned	-	-
Nonvested-end of year	-	$ -

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 year ended June 30, 2005, risk-free interest rate of 4.28%, dividend yield of 0%, volatility factor of the expected market price of the Company's common stock of 43.97%, and a weighted-average expected life of the options of 4.76 years. The fair value of the options granted at the grant date was $8.0 million for the year ended June 30, 2005. No options were granted during the years ended December 31, 2007 and 2006 or six months ended December 31, 2005.

A summary of the restricted stock (nonvested stock) activity under the Company's plan and related information for the year ended December 31, 2007 follows:

	Year Ended December 31, 2007			
	Nonvested Stock	Weighted-Average Grant-Date Fair Value	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Nonvested-beginning of year	627,500	$ 20.78		
Granted	1,780,787	21.56		
Vested	(266,493)	(20.76)		
Expired / Returned	(27,173)	(18.32)		
Nonvested-end of year	2,114,621	$ 21.47	6.90	$39,861,000

(6) Stockholders' Equity, Continued

Restricted Stock - Directors and Employees

The total fair value of restricted stock vested during the years ended December 31, 2007 and 2006, and the six months ended December 31, 2005 was $5.2 million, $2.4 million and $697,000, respectively.

At December 31, 2007, 2006 and 2005, the total unrecognized compensation cost related to the non-vested portion of restricted stock and stock options was $20.8 million, $11.4 million and $5.8 million which is expected to be recognized over a weighted average period of 6.90, 2.08 and 4.75 years, respectively.

Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and year ended June 30, 2005, was $686,000, $3.6 million, $625,000, and $132,000, respectively. Tax benefits realized from the stock options exercised during the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and year ended June 30, 2005, was zero, zero, zero, and $1.3 million, respectively. During the years ended December 31, 2007 and 2006 and six months ended December 31, 2005, $8.0 million, $4.6 million and $6.6 million, respectively, of tax benefits were generated from the exercise of stock options; however, such benefit will not be recognized in stockholders' equity until the period that these amounts decrease taxes payable.

(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 vest over a six year service period.

For the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and fiscal year ended June 30, 2005, the Company contributed $632,000, $528,000, $240,000, and $291,000, respectively, under its profit sharing plan.

The Company adopted a 401(k) 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 401(k) 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 compensation.

(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 Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"). Effective July 1, 2007, the Company elected to discontinue cash flow hedge accounting on a prospective basis. Beginning July 1, 2007, the Company recognizes mark-to-market gains and losses in current earnings instead of deferring those amounts in accumulated other comprehensive income. As a result of the Company's election to discontinue hedge accounting, the amount recorded in accumulated other comprehensive income for hedges that were effective as of June 30, 2007 was fixed until the period those derivatives were settled, with all subsequent changes in fair value recorded in gain (loss) from ineffective derivative contracts. All amounts in accumulated other comprehensive income as of June 30, 2007 were reclassified to gain (loss) on effective derivative contracts as of December 31, 2007, as all such derivatives had settled.

(8) Commodity Derivative Instruments and Hedging Activities, Continued

At December 31, 2007, the Company's outstanding derivative contracts were 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 foregoing the benefit of price increases in excess of the ceiling price on the hedged production.

The following table summarizes our derivative contracts outstanding at December 31, 2007:

Commodity	Volume		Price Floor / Price Ceiling		Term	Index	Net Fair Value Asset (Liability) at December 31, 2007 (In thousands)
Crude oil	1,200	Bbls / day	$ 65.00 /	$ 80.03	Jan '08 - Mar '08	NYMEX – WTI	$ (1,705)
Crude oil	1,200	Bbls / day	$ 65.00 /	$ 79.77	Apr '08 - June '08	NYMEX – WTI	(1,620)
Crude oil	1,200	Bbls / day	$ 65.00 /	$ 79.86	July '08 - Sept '08	NYMEX – WTI	(1,522)
Crude oil	1,200	Bbls / day	$ 65.00 /	$ 79.83	Oct '08 - Dec '08	NYMEX – WTI	(1,448)
Natural gas	15,000	MMBtu / day	$ 6.50 /	$ 8.30	Jan '08 - Dec '08	CIG	2,404
Natural gas	5,000	MMBtu / day	$ 6.50 /	$ 8.40	Jan '08 - Mar '08	CIG	211
Natural gas	10,000	MMBtu / day	$ 6.00 /	$ 7.25	Apr '08 -Sept '08	CIG	139
Natural gas	10,000	MMBtu / day	$ 6.50 /	$ 7.90	Oct '08 - Dec '08	CIG	176
							$ (3,365)

The fair value of the Company's derivative instruments liability was $3.4 million at December 31, 2007. Subsequent to year-end, the Company entered into new CIG gas hedges for 10,000 Mmbtu per day for the second and third quarters of 2008 with a floor price of $6.50 and ceiling prices of $7.70 and $8.15 per Mmbtu, respectively. The Company also entered into new CIG gas hedges for 35,000 Mmbtu per day for the first quarter of 2009 with a floor price of $7.50 per Mmbtu and a ceiling price of $9.88 per Mmbtu. The fair value of the derivative liability at February 26, 2008 was $15.2 million.

The net gains (losses) from effective hedging activities recognized in the Company's statements of operations were $12.9 million, ($4.7 million), ($3.4 million), and ($630,000), for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and year ended June 30, 2005, respectively. These gains (losses) are recorded as an increase or decrease in revenues.

(9) Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS 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 December 31, 2007 and 2006, six months ended December 31, 2005 and fiscal year ended June 30, 2005:

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
	(In thousands)			
CURRENT:				
U.S. - Federal	$ 47	$ 192	$ -	$ -
U.S. - State	(5)	-	-	-
Foreign	-	-	-	-
DEFERRED:				
U.S. - Federal	2,452	(11,052)	(9,458)	(10,898)
U.S. - State	183	(1,763)	(1,415)	(1,071)
Foreign	-	-	-	-
	$ 2,677	$ (12,623)	$ (10,873)	$ (11,969)

Income from continuing operations before taxes consists of the following for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and the fiscal year ended June 30, 2005:

U.S.	$ (160,228)	$ (33,623)	$ (29,203)	$ (10,353)
Foreign	-	-	-	-
Income (loss) from continuing operations before taxes	$ (160,228)	$ (33,623)	$ (29,203)	$ (10,353)

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 December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
Federal statutory rate	(35.0) %	(35.0) %	(35.0) %	35.0 %
State income taxes, net of federal benefit	(2.1)	(2.7)	(3.1)	3.4
Investment in DHS	-	-	(5.8)	3.5
Change in valuation allowance	40.6	-	1.0	(69.6)
Other	(1.8)	0.2	5.7	(1.8)
Actual income tax rate	1.7 %	(37.5) %	(37.2) %	(29.5) %

(9) Income Taxes, Continued

Included in the consolidated statement of operations as a component of discontinued operations for the year ended December 31, 2006 is a $5.0 million deferred tax provision on the sale and operations of properties that were sold during the period. Also included in the consolidated statement of operations as a component of extraordinary gain for the year ended December 31, 2006 is a $3.2 million deferred tax provision on the sale of properties acquired in the Castle acquisition.

Deferred tax assets (liabilities) are comprised of the following at December 31, 2007, December 31, 2006, December 31, 2005, and June 30, 2005:

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
	(In thousands)			
Current deferred tax asset (liability)				
Derivative instruments	$ 1,249	$ (3,844)	$ 4,665	$ 2,638
Accrued bonuses	1,737	1,138	452	-
Allowance for doubtful accounts	236	38	38	38
Accrued vacation liability	212	140	82	-
Prepaid insurance and other	(394)	(365)	-	-
Total current deferred tax assets	3,040	(2,893)	5,237	2,676
Less valuation allowance	(2,890)	-	-	-
Net current deferred tax asset (liability)	$ 150	$ (2,893)	$ 5,237	$ 2,676
Long-term deferred tax asset (liability):				
Deferred tax assets:				
Net operating loss [1]	$ 56,649	$ 15,306	$ 16,074	$ 14,544
Asset retirement obligation	1,976	1,754	1,306	1,419
Derivative instruments	-	-	2,204	1,211
Percentage depletion	596	531	530	541
Drilling equipment	-	-	792	403
Equity compensation	4,807	2,142	942	-
Minimum tax credit	1,221	1,368	-	-
Other	153	558	152	66
Total long-term deferred tax assets	65,402	21,659	22,000	18,184
Valuation allowance	(55,187)	(661)	(712)	(1,139)
Net deferred tax asset	10,215	20,998	21,288	17,045
Deferred tax liabilities:				
Property and equipment	(19,261)	(23,081)	(17,879)	(11,256)
Investment in DHS	-	-	(2,001)	(399)
Investments – available for sale	-	-	-	(503)
Other	(39)	(1,577)	(86)	-
Total long-term deferred tax liabilities	(19,300)	(24,658)	(19,966)	(12,158)
Net long-term deferred tax asset (liability)	$ (9,085)	$ (3,660)	$ 1,322	$ 4,887
Total deferred tax assets before valuation allowance	$ 68,836	$ 22,975	$ 27,237	$ 20,860
Total deferred tax liabilities	$ 19,694	$ 28,867	$ 19,966	$ 12,158

[1] Included in net operating loss carryforwards is $1.25 million at June 30, 2005 that related to the tax effect of stock options exercised and restricted stock for which the benefit was recognized in stockholders' equity rather than in operations in accordance with FAS 109. Not included in the deferred tax asset for net operating loss at December 31, 2007 and 2006 is approximately $7.9 million and $11.4 million, respectively, that relates to the tax effect of stock options exercised for which the benefit will not be recognized in stockholders' equity until the period that these amounts decrease taxes payable. The related $38.1 million tax deduction is included in the table of net operating losses shown below.

(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 results of operations, and tax planning strategies in making this assessment. Based upon the level of historical taxable income, significant book losses during the year ended December 31, 2007, and projections for future results of operations over the periods in which the deferred tax assets are deductible, among other factors, management concluded during the second quarter of 2007 and continues to conclude that the Company does not meet the "more likely than not" requirement of SFAS 109 in order to recognize deferred tax assets. Accordingly, for the year ended December 31, 2007, the Company recorded in income tax expense an increase to the valuation allowance of $57.4 million offsetting the Company's deferred tax assets.

At December 31, 2007, the Company had net operating loss carryforwards for regular and alternative minimum tax purposes as follows:

Regular tax net operating loss	$191,918
Alternative minimum tax net operating loss	176,617

If not utilized, the tax net operating loss carryforwards will expire from 2008 through 2027.

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

2008	$ 720
2009	3,914
2010	6,004
2011	5,939
2012	994
2013 and thereafter	174,347
	$191,918

In August 2007, the Company experienced cumulative ownership changes as defined by the Internal Revenue Code ("IRC") 382 and as a result, a portion of the Company's net operating loss utilization after the change date will be subject to IRC 382 limitations of approximately $45.0 million for federal income taxes.

(10) Related Party Transactions

Transactions with Directors and Officers

On September 29, 2005 we acquired an undivided 50% working interest in approximately 145,000 net undeveloped acres in the Columbia River Basin in Washington and purchased an interest in undeveloped acreage in the Piceance Basin in Colorado from Savant Resources, LLC ("Savant") for an aggregate purchase price of $85.0 million in cash. At the time of the transaction, James Wallace, one of our directors, owned approximately a 1.7% interest in and served as a director of Savant. The majority of the acquired acreage in the Columbia River Basin consolidates our current leasehold position.

During the quarter ended September 30, 2005, DHS borrowed $8.0 million from Chesapeake, a related party who owns approximately a 45% interest in DHS. The loan was subsequently paid in full.

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 of Mr. Larson and Mr. Parker earned approximately $110,000, $142,000, $58,000, and $100,000, for their respective 1% ORRI during the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and fiscal year ended June 30, 2005, respectively.

(10) Related Party Transactions, Continued

As of December 31, 2007, the Company's executive officers had employment agreements which, among other things, include clauses that provide for the payment of certain amounts to the executives upon termination of employment and for the continuation of group medical benefits after such termination.

Accounts Receivable Related Parties

At December 31, 2007 and 2006, the Company had $276,000 and $30,000 of receivables from related parties, respectively. These amounts include drilling costs and lease operating expense on wells owned by the related parties and operated by the Company.

(11) Earnings Per Share

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

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
	(In thousands, except per share amounts)			
Net income (loss)	$(149,347)	$ 435	$ (590)	$ 15,050
Basic weighted-average shares outstanding	61,297	51,702	44,959	40,327
Add: dilutive effects of stock options and unrestricted stock grants	-	1,611	-	1,693
Add: dilutive effect of 3¾% Convertible Notes using the if-converted method	-	-	-	-
Diluted weighted-average common shares outstanding	61,297	53,313	44,959	42,020
Basic net income (loss) per common share	$ (2.44)	$ .01	$ (.01)	$ .37
Diluted net income (loss) per common share[1]	$ (2.44)	$ .01	$ (.01)	$ .36

[1]The denominator for diluted net income (loss) per common share for the year ended December 31, 2007 and the six months ended December 31, 2005 excludes 7,951,000 and 3,231,000, respectively, of potentially dilutive shares because such shares were anti-dilutive.

(12) Guarantor Financial Information

On March 15, 2005 Delta issued 7% Senior Notes ("Senior Notes") that mature in 2015 for an aggregate amount of $150.0 million and on which interest is paid semiannually on April 1st and October 1st. The net proceeds from the Senior Notes were used to refinance debt outstanding under the Company's credit facility. In addition, on April 25, 2007 the Company issued 3 ¾% Convertible Senior Notes due in 2037 ("Convertible Notes") for aggregate proceeds of $111.6 million and on which interest is paid semiannually on May 1 and November 1. The proceeds of the Convertible Notes were used for capital expenditures. Both the Senior Notes and the Convertible Notes are guaranteed by Piper Petroleum Company and all of the Company's other wholly-owned subsidiaries ("Guarantors"). Each of the Guarantors, fully, jointly and severally, irrevocably and unconditionally guarantees the performance and payment when due of all the obligations under the Senior Notes and the Convertible Notes. DHS, CRBP, PGR, and Amber ("Non-guarantors") are not guarantors of the indebtedness under the Senior Notes or the Convertible Notes.

The following financial information sets forth the Company's condensed consolidated balance sheets as of December 31, 2007 and 2006, the condensed consolidated statements of operations for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and the year ended June 30, 2005, and the condensed consolidated statements of cash flows for the years ended December 31, 2007 and 2006, six months ended December 31, 2005, and year ended June 30, 2005 (in thousands):

Condensed Consolidated Balance Sheet
December 31, 2007

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 98,918	$ 898	$ 33,253	$ -	$ 133,069
Property and equipment:					
Oil and gas	918,247	487	80,784	(11,644)	987,874
Drilling rigs and trucks	595	-	145,502	-	146,097
Other	35,444	4,316	1,449	-	41,209
Total property and equipment	954,286	4,803	227,735	(11,644)	1,175,180
Accumulated DD&A	(203,091)	(125)	(41,937)	-	(245,153)
Net property and equipment	751,195	4,678	185,798	(11,644)	930,027
Investment in subsidiaries	87,961	-	-	(87,961)	-
Other long-term assets	29,786	3,800	8,513	-	42,099
Total assets	$ 967,860	$ 9,376	$ 227,564	$ (99,605)	$1,105,195
Current liabilities	$ 135,997	$ 188	$ 7,011	$ -	$ 143,196
Long-term liabilities					
Long-term debt and deferred taxes	336,409	1,800	83,935	-	422,144
Asset retirement obligation	3,976	9	169	-	4,154
Total long-term liabilities	340,385	1,809	84,104	-	426,298
Minority interest	27,296	-	-	-	27,296
Stockholders' equity	464,182	7,379	136,449	(99,605)	508,405
Total liabilities and stockholders' equity	$ 967,860	$ 9,376	$ 227,564	$ (99,605)	$1,105,195

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended December 31, 2007

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 102,735	$ 577	$ 95,288	$ (34,410)	$ 164,190
Operating expenses:					
Lease operating expense	28,207	118	1,060	-	29,385
Depreciation and depletion	59,461	11	25,953	-	85,425
Exploration expense	9,062	-	-	-	9,062
Drilling and trucking operations	-	-	59,720	(22,766)	36,954
Dry hole, abandonment and impaired	85,084	-	-	-	85,084
General and administrative	44,543	(1)	5,079	-	49,621
Total expenses	226,357	128	91,812	(22,766)	295,531
Operating income (loss)	(123,622)	449	3,476	(11,644)	(131,341)
Other income and expenses	(21,500)	88	(8,705)	1,230	(28,887)
Income tax (expense) benefit	(4,486)	-	1,809	-	(2,677)
Discontinued operations	13,558	-	-	-	13,558
Net income (loss)	$(136,050)	$ 537	$ (3,420)	$ (10,414)	$(149,347)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2007

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 67,669	$ 208	$ 16,515	$ 84,392
Investing activities	(284,900)	(1,538)	(38,586)	(325,024)
Financing activities	219,904	-	23,153	243,057
Net increase (decrease) in cash and cash equivalents	2,673	(1,330)	1,082	2,425
Cash at beginning of the period	2,282	1,637	3,747	7,666
Cash at the end of the period	$ 4,955	$ 307	$ 4,829	$ 10,091

(12) Guarantor Financial Information, Continued

Condensed Consolidated Balance Sheet
December 31, 2006

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Current assets	$ 61,946	$ 2,447	$ 25,401	$ -	$ 89,794
Property and equipment:					
Oil and gas	735,412	444	58,078	(12,119)	781,815
Drilling rigs and trucks	595	-	135,443	-	136,038
Other	23,435	4,320	1,137	-	28,892
Total property and equipment	759,442	4,764	194,658	(12,119)	946,745
Accumulated DD&A	(111,422)	(119)	(20,004)	-	(131,545)
Net property and equipment	648,020	4,645	174,654	(12,119)	815,200
Investment in subsidiaries	66,366	-	-	(66,366)	-
Other long-term assets	11,423	3,521	9,385	-	24,329
Total assets	$ 787,755	$ 10,613	$ 209,440	$ (78,485)	$ 929,323
Current liabilities	$ 88,344	$ 1,200	$ 10,035	$ -	$ 99,579
Long-term liabilities					
Long-term debt and deferred taxes	283,709	1,600	84,799	-	370,108
Asset retirement obligation	3,921	9	83	-	4,013
Total long-term liabilities	287,630	1,609	84,882	-	374,121
Minority interest	27,390	-	-	-	27,390
Stockholders' equity	384,391	7,804	114,523	(78,485)	428,233
Total liabilities and stockholders' equity	$ 787,755	$ 10,613	$ 209,440	$ (78,485)	$ 929,323

Condensed Consolidated Statement of Operations
Year Ended December 31, 2006

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 85,025	$ 1,362	$ 85,306	$ (25,033)	$ 146,660
Operating expenses:					
Lease operating expense	22,553	471	393	-	23,417
Depreciation and depletion	52,742	112	17,530	-	70,384
Exploration expense	4,687	-	3	-	4,690
Drilling and trucking operations	-	-	47,077	(12,914)	34,163
Dry hole, abandonment and impaired	15,682	-	-	-	15,682
General and administrative	32,266	86	3,344	-	35,696
Gain on sale of oil and gas properties	(20,034)	-	-	-	(20,034)
Total expenses	107,896	669	68,347	(12,914)	163,998
Income (loss) from continuing operations	(22,871)	693	16,959	(12,119)	(17,338)
Other income and expenses	(6,402)	(23)	(7,264)	(2,596)	(16,285)
Income tax benefit	15,687	-	(3,064)	-	12,623
Discontinued operations	15,875	-	-	-	15,875
Extraordinary gain	-	5,560	-	-	5,560
Net income (loss)	$ 2,289	$ 6,230	$ 6,631	$ (14,715)	$ 435

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2006

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 35,617	$ (237)	$ 18,006	$ 53,386
Investing activities	(148,788)	20,941	(75,238)	(203,085)
Financing activities	113,505	(19,283)	57,624	151,846
Net increase (decrease) in cash and cash equivalents	334	1,421	392	2,147
Cash at beginning of the period	1,949	216	3,354	5,519
Cash at the end of the period	$ 2,283	$ 1,637	$ 3,746	$ 7,666

Condensed Consolidated Statement of Operations
Six Months Ended December 31, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 37,614	$ 1,616	$ 16,316	$ (7,220)	$ 48,326
Operating expenses:					
Lease operating expense	9,464	178	-	-	9,642
Depreciation and depletion	12,254	158	2,846	-	15,258
Exploration expense	2,058	(1)	4	-	2,061
Drilling and trucking operations	-	-	9,545	(3,724)	5,821
Dry hole, abandonment and impaired	5,423	-	-	-	5,423
General and administrative	15,263	7	1,221	-	16,491
Total expenses	44,462	342	13,616	(3,724)	54,696
Income (loss) from continuing operations	(6,848)	1,274	2,700	(3,496)	(6,370)
Other income and expenses	(21,146)	4	(1,003)	(688)	(22,833)
Income tax benefit	10,873	-	-	-	10,873
Discontinued operations	17,740	-	-	-	17,740
Net income (loss)	$ 619	$ 1,278	$ 1,697	$ (4,184)	$ (590)

Condensed Consolidated Statement of Cash Flows
Six Months Ended December 31, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
Operating activities	$ 21,477	$ (1,244)	$ 4,646	$ 24,879
Investing activities	(96,840)	1,472	(51,140)	(146,508)
Financing activities	75,314	(209)	49,802	124,907
Net increase (decrease) in cash and cash equivalents	(49)	19	3,308	3,278
Cash at beginning of the period	1,999	196	46	2,241
Cash at the end of the period	$ 1,950	$ 215	$ 3,354	$ 5,519

(12) Guarantor Financial Information, Continued

Condensed Consolidated Statement of Operations
Year Ended June 30, 2005

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Adjustments/ Eliminations	Consolidated
Total revenue	$ 50,159	$ 1,657	$ 7,319	$ (2,523)	$ 56,612
Operating expenses:					
Lease operating expense	12,611	489	-	-	13,100
Depreciation and depletion	13,907	148	1,525	-	15,580
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	51,232	646	9,457	(2,133)	59,202
Income (loss) from continuing operations	(1,073)	1,011	(2,138)	(390)	(2,590)
Other income and expenses	(7,792)	31	(2)	-	(7,763)
Income tax benefit	11,969	-	-	-	11,969
Discontinued operations	13,434	-	-	-	13,434
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

(13) Commitments and Contingencies

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 December 31, 2007 and 2006, six months ended December 31, 2005 and year ended June 30, 2005, was approximately $1,150,000, $856,000, $432,000, and $491,000, respectively. The following table summarizes the future minimum payments under all non-cancelable operating lease obligations:

	(In thousands)
2008	$ 3,527
2009	3,413
2010	1,918
2011	1,796
2012	1,201
2013 and thereafter	2,394
	$14,249

On April 30, 2007, the Company entered into agreements with four executive officers which provide for severance payments, three 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. These agreements replace similar agreements that expired on December 31, 2006.

Offshore Litigation

The Company and its 92% owned subsidiary, Amber, are among twelve plaintiffs in a lawsuit that was filed in the United States Court of Federal Claims (the "Court") in Washington, D.C. alleging that the U.S. government materially breached the terms of forty undeveloped federal leases, some of which are part of the Company's offshore California properties. On November 15, 2005 and October 31, 2006, the Court granted summary judgment as to liability and partial summary judgment as to damages with respect to thirty six of the forty total federal leases that are the subject of the litigation. Under a restitution theory of damages, the Court ruled that the government must give back to the current lessees the more than $1.1 billion in lease bonuses it had received at the time of sale. On January 19, 2006, the government filed a motion for reconsideration of the Court's ruling as it relates to a single lease owned entirely by the Company ("Lease 452"). In its motion for reconsideration, the government has asserted that the Company should not be able to recover lease bonus payments for Lease 452 because, allegedly, a significant portion of the hydrocarbons has been drained by wells that were drilled on an immediately adjacent lease. The amount of lease bonus payments attributable to Lease 452 is approximately $92.0 million. A trial on the motion for reconsideration was completed in January 2008 and post-trial briefing is currently in process. The Company believes that the government's assertion is without merit, but it cannot predict with certainty the ultimate outcome of this matter.

On January 12, 2007, the Court entered an order of final judgment awarding the lessees restitution of the original lease bonuses paid for thirty five of the forty lawsuit leases. Under this order the Company is entitled to receive a gross amount of approximately $58.5 million and Amber is entitled to receive a gross amount of approximately $1.5 million as reimbursement for the lease bonuses paid for all lawsuit leases other than Lease 452. The government has appealed the order and contends that, among other things, the Court erred in finding that it breached the leases, and in allowing the current lessees to stand in the shoes of their predecessors for the purposes of determining the amount of damages that they are entitled to receive. The current lessees are also appealing the order of final judgment to, among other things, challenge the Court's rulings that they cannot recover their and their predecessors' sunk costs as part of their restitution claim. No payments will be made until all appeals have either been waived or exhausted. In the event that the Company ultimately receives any proceeds as the result of this litigation, it will be obligated to pay a portion to landowners and other owners of royalties and similar interests, to pay the litigation expenses and to fulfill certain pre-existing contractual commitments to third parties.

(13) Commitments and Contingencies, Continued

Shareholder Derivative Suit

Within the past two years, there has been significant focus on corporate governance and accounting practices in the grant of equity based awards to executives and employees of publicly traded companies, including the use of market hindsight to select award dates to favor award recipients. After being identified in a third-party report as statistically being at risk for possibly backdating option grants, in May 2006 the Company's Board of Directors created a special committee comprised of outside directors of the Company. The special committee, which was advised by independent legal counsel and advisors, undertook a comprehensive review of the Company's historical stock option practices and related accounting treatment. In June 2006 the Company received a subpoena from the U.S. Attorney for the Southern District of New York and an inquiry from the staff of the SEC related to the Company's stock option grants and related practices. The special committee of the Company's Board of Directors reported to the Board that, while its review revealed deficiencies in the documentation of the Company's option grants in prior years, there was no evidence of option backdating or other misconduct by the Company's executives or directors in the timing or selection of the Company's option grant dates, or that would cause the Company to conclude that its prior accounting for stock option grants was incorrect in any material respect. The Company provided the results of the internal investigation to the U.S. Attorney and to the SEC in August of 2006, and was subsequently informed by both agencies that the matter had been closed.

During September and October of 2006, three separate shareholder derivative actions were filed on the Company's behalf in U.S. District Court for the District of Colorado relating to the options backdating issue, all of which were consolidated into a single action. The consolidated complaint alleged that certain of the Company's executive officers and directors engaged in various types of misconduct in connection with certain stock option grants. Specifically, the plaintiffs alleged that the defendant directors, in their capacity as members of the Company's Board of Directors and its Audit or Compensation Committee, at the behest of the defendants who are or were officers and to benefit themselves, backdated the Company's stock option grants to make it appear as though they were granted on a prior date when the Company's stock price was lower. They alleged that these backdated options unduly benefited the defendants who are or were officers and/or directors, resulted in the Company issuing materially inaccurate and misleading financial statements and caused the Company to incur substantial damages. The action also sought to have the current and former officers and directors who are defendants disgorge to the Company certain options they received, including the proceeds of options exercised, as well as certain equitable relief and attorneys' fees and costs. On September 26, 2007, the Court entered an Order dismissing the action for failing to plead sufficient facts to support the claims that were made in the complaint, and stayed the dismissal for ten days to allow the Plaintiffs to file a motion for leave to file an amended complaint. Extensions were granted and the Plaintiffs filed such a motion on October 29, 2007. The stay will remain in effect until the Court rules on the motion.

Castle/Longs Trust Litigation

As a result of the acquisition of Castle Energy in April 2006, the Company's wholly-owned subsidiary, DPCA LLC, as successor to Castle, became party to Castle's ongoing litigation with the Longs Trust in District Court in Rusk County, Texas. The Longs Trust litigation, which was originally the subject of a jury trial in November 2000, has been separated into two pending suits, one in which the Longs Trust is seeking relief on contract claims regarding oil and gas sales and gas balancing under joint operating agreements with various Castle entities, and the other in which Castle's claims for unpaid joint interest billings and attorneys' fees in the amount of $964,000, plus prejudgment interest, have been granted by the trial court and upheld on appeal. The Company intends to vigorously defend the Longs Trust breach of contract claims. The Company has not accrued any recoveries associated with the judgment against the Longs Trust, but will do so when and if they are ultimately collected.

Management does not believe that these proceedings, individually or in the aggregate, will have a material adverse effect on the Company's financial position, results of operations or cash flows.

(14) Business Segments

The Company has two reportable segments: oil and gas exploration and production ("Oil and Gas") and drilling operations ("Drilling") through its ownership in DHS. Following is a summary of segment results for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and year ended June 30, 2005.

	Oil and Gas	Drilling	Inter-segment Eliminations	Consolidated
		(In thousands)		
Year Ended December 31, 2007				
Revenues from external customers	$ 107,413	$ 56,777	$ -	$ 164,190
Inter-segment revenues	-	34,410	(34,410)	-
Total revenues	107,413	91,187	(34,410)	164,190
Operating income (loss)	(124,135)	4,438	(11,644)	(131,341)
Other income and (expense) [1]	(21,413)	(8,705)	1,231	(28,887)
Income (loss) from continuing operations, before tax	$(145,548)	$ (4,267)	$(10,413)	$(160,228)
Total Assets	$ 996,549	$ 146,314	$(37,668)	$1,105,195
Year Ended December 31, 2006				
Revenues from external customers	$ 89,511	$ 57,149	$ -	$ 146,660
Inter-segment revenues	-	25,033	(25,033)	-
Total revenues	89,511	82,182	(25,033)	146,660
Operating income (loss)	(20,685)	15,467	(12,120)	(17,338)
Other income and (expense) [1]	(6,426)	(7,264)	(2,595)	(16,285)
Income (loss) from continuing operations, before tax	$ (27,111)	$ 8,203	$(14,715)	$ (33,623)
Total Assets	$ 819,470	$ 148,869	$(39,016)	$ 929,323
Six Months Ended December 31, 2005				
Revenues from external customers	$ 39,230	$ 9,096	$ -	$ 48,326
Inter-segment revenues	-	7,220	(7,220)	-
Total revenues	39,230	16,316	(7,220)	48,326
Operating income (loss)	(5,631)	2,757	(3,496)	(6,370)
Other income and (expense) [1]	(21,142)	(1,003)	(688)	(22,833)
Income (loss) from continuing operations, before tax	$ (26,773)	$ 1,754	$ (4,184)	$ (29,203)
Year Ended June 30, 2005				
Revenues from external customers	$ 51,816	$ 4,796	$ -	$ 56,612
Inter-segment revenues	-	2,523	(2,523)	-
Total revenues	51,816	7,319	(2,523)	56,612
Operating income (loss)	(174)	(2,028)	(388)	(2,590)
Other income and (expense) [1]	(8,778)	(2)	1,017	(7,763)
Income (loss) from continuing operations, before tax	$ (8,952)	$ (2,030)	$ 629	$ (10,353)

[1] Includes interest and financing costs, gain on sale of marketable securities, unrealized losses on derivative contracts and other miscellaneous income for Oil and Gas, and other miscellaneous income for Drilling. Minority interest is included in inter-segment eliminations.

(15) Selected Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31,	June 30,	September 30,	December 31,
	(In thousands, except per share amounts)			
Year Ended December 31, 2007				
Total revenue	$ 36,913	$ 38,200	$ 44,019	$ 45,058
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	(25,135)	(83,869)	(15,056)	(36,168)
Net income (loss)	(18,744)	(94,205)	(6,418)	(29,980)
Net income (loss) per common share: [1]				
Basic	$ (.34)	$ (1.51)	$ (.10)	$ (.47)
Diluted	$ (.34)	$ (1.51)	$ (.10)	$ (.47)
Year Ended December 31, 2006				
Total revenue	$ 31,717	$ 36,564	$ 41,034	$ 37,345
Income (loss) from continuing operations before income taxes, discontinued operations and cumulative effect	17,554	(8,365)	(23,425)	(19,387)
Net income (loss)	13,805	4,210	(7,080)	(10,500)
Net income (loss) per common share: [1]				
Basic	$ .28	$ .08	$ (.13)	$ (.20)
Diluted	$ .27	$ .08	$ (.13)	$ (.20)

[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.

(16) Disclosures About Capitalized Costs, Costs Incurred and Major Customers (Unaudited)

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

	December 31, 2007	December 31, 2006	December 31, 2005	June 30, 2004
	(In thousands)			
Unproved offshore California properties	$ 14,789	$ 12,484	$ 10,960	$ 10,925
Unproved onshore domestic properties	232,677	205,089	156,183	91,010
Proved offshore California properties	17,733	16,906	13,678	12,207
Proved onshore domestic properties	722,675	547,336	424,988	353,099
	987,874	781,815	605,809	467,241
Accumulated depreciation and depletion	(204,014)	(116,151)	(57,922)	(43,034)
	$ 783,860	$ 665,664	$ 547,887	$ 424,207

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

	Years Ended December 31, 2007		Years Ended December 31, 2006		Six Months Ended December 31, 2005		Year Ended June 30, 2005	
	(In thousands)							
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Unproved property acquisition costs	$ 26,408	$ 2,305	$ 60,002	$ 1,525	$ 88,116	$ 35	$ 25,383	$ 81
Proved property acquisition costs	45,857	301	2,972	283	4,386	82	81,190	-
Developed costs incurred on undeveloped reserves	143,630	526	43,198	2,946	30,891	1,389	72,413	3,104
Development costs – other	119,607	-	159,807	-	54,591	-	36,369	-
Exploration costs	9,062	-	4,690	-	2,061	-	6,155	-
	$ 344,564	$ 3,132	$ 270,669	$ 4,754	$ 180,045	$ 1,506	$ 221,510	$ 3,185

[1] Included in costs incurred are asset retirement obligation costs for all periods presented.

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

	Years Ended December 31, 2007		Years Ended December 31, 2006		Six Months Ended December 31, 2005		Year Ended June 30, 2005	
	(In thousands)							
	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore	Onshore	Offshore
Revenue:								
Oil and gas revenues	$ 86,838	$ 7,721	$ 86,627	$ 7,596	$ 38,833	$ 3,810	$ 47,255	$ 5,191
Expenses:								
Production costs	25,747	3,638	19,711	3,705	7,517	2,128	9,260	3,840
Depletion	62,088	1,285	53,190	1,049	11,593	382	12,544	720
Exploration	9,062	-	4,690	-	2,061	-	6,155	-
Abandonment and impaired properties	58,411	-	11,359	-	-	-	-	-
Dry hole costs	26,673	-	4,323	-	5,423	-	2,771	-
Results of operations of oil and gas producing activities	$(95,143)	$ 2,798	$ (6,646)	$ 2,842	$ 12,239	$ 1,300	$ 16,525	$ 631
Income from operations of properties sold, net	17,556	-	9,163	-	5,952	-	13,434	-
Gain (loss) on sale of properties	(3,998)	-	6,712	-	11,788	-	-	-
Results of discontinued operations of oil and gas producing activities	$ 13,558	$ -	$ 15,875	$ -	$ 17,740	$ -	$ 13,434	$ -

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

During the year ended December 31, 2007, two customers accounted individually for 27% and 13% of the Company's total oil and gas sales. During the year ended December 31, 2006, two customers individually accounted for 24% and 15% of the Company's total oil and gas sales. During the six months ended December 31, 2005, three customers individually accounted for 15%, 14% and 12% of the Company's total oil and gas sales. During the fiscal year ended June 30, 2005, one customer individually accounted for 10% of the Company's total oil and gas sales.

(17) 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.

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

"Prepared" reserves are those quantities of reserves which were prepared by an independent petroleum consultant. "Audited" reserves are those quantities of revenues which were estimated by the Company's employees and audited by an independent petroleum consultant. An audit is an examination of a company's proved oil and gas reserves and net cash flow by an independent petroleum consultant that is conducted for the purpose of expressing an opinion as to whether such estimates, in aggregate, are reasonable and have been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

Estimates of the Company's oil and natural gas reserves and present values as of December 31, 2007, December 31, 2006, December 31, 2005, and June 30, 2005 were prepared by Ralph E. Davis Associates, Inc., the Company's independent reserve engineers with respect to onshore reserves for all periods presented and with respect to offshore reserves as of December 31, 2007 and 2006.

Estimates of the Company's offshore reserves were prepared by Mannon Associates Inc. as of December 31, 2005 and June 30, 2005.

A summary of changes in estimated quantities of proved reserves for the years ended December 31, 2007 and 2006, six months ended December 31, 2005 and the year ended June 30, 2005 is as follows:

	Onshore		Offshore
	GAS (MMcf)	OIL (MBbl)	OIL (MBbl)
		(In thousands)	
Estimated Proved Reserves: 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)
Estimated Proved Reserves: Balance at June 30, 2005	141,041	12,373	1,498
Revisions of quantity estimate	(4,683)	(506)	(468)
Extensions and discoveries	58,725	2,542	-
Purchase of properties	11,816	-	-
Sale of properties	(22,025)	(221)	-
Production	(3,720)	(428)	(81)
Estimated Proved Reserves: Balance at December 31, 2005	181,154	13,760	949
Revisions of quantity estimate	(23,050)	(2,943)	(328)
Extensions and discoveries	90,738	3,533	-
Purchase of properties	7,590	3	-
Sale of properties	(23,706)	(673)	-
Production	(8,022)	(1,192)	(162)
Estimated Proved Reserves: Balance at December 31, 2006	224,704	12,488	459
Revisions of quantity estimate	23,932	(2,126)	25
Extensions and discoveries	86,269	2,423	-
Purchase of properties	10,559	266	-
Sale of properties	(24,738)	(1,425)	-
Production	(11,253)	(940)	(145)
Estimated Proved Reserves: Balance at December 31, 2007	309,473	10,686	339

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

Proved developed reserves:

June 30, 2004	55,786	6,240	695
June 30, 2005	70,568	6,947	585
December 31, 2005	56,852	7,171	657
December 31, 2006	65,026	5,828	459
December 31, 2007	92,194	4,209	339

(17) 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
December 31, 2007			
Future net cash flows	$ 2,923,129	$ 28,352	$ 2,951,481
Future costs:			
Production	723,689	11,921	735,610
Development and abandonment	585,622	-	585,622
Income taxes	224,073	2,281	226,354
Future net cash flows	1,389,745	14,150	1,403,895
10% discount factor	(699,896)	(2,125)	(702,021)
Standardized measure of discounted future net cash flows	$ 689,849	$ 12,025	$ 701,874
Estimated future development cost anticipated for fiscal 2008 and 2009 on existing properties	$ 334,326	$ -	$ 334,326
December 31, 2006			
Future net cash flows	$ 1,743,639	$ 21,695	$ 1,765,334
Future costs:			
Production	466,919	14,727	481,646
Development and abandonment	329,355	-	329,355
Income taxes	76,373	562	76,935
Future net cash flows	870,992	6,406	877,398
10% discount factor	(393,249)	(915)	(394,164)
Standardized measure of discounted future net cash flows	$ 477,743	$ 5,491	$ 483,234
Estimated future development cost anticipated for fiscal 2007 and 2008 on existing properties	$ 250,224	$ -	$ 250,224
December 31, 2005			
Future net cash flows	$ 2,613,958	$ 45,420	$ 2,659,378
Future costs:			
Production	481,537	21,970	503,507
Development and abandonment	318,704	2,950	321,654
Income taxes	471,125	5,325	476,450
Future net cash flows	1,342,592	15,175	1,357,767
10% discount factor	(604,355)	(3,788)	(608,143)
Standardized measure of discounted future net cash flows	$ 738,237	$ 11,387	$ 749,624
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

(17) 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 December 31, 2007 and 2006, six months ended December 31, 2005 and the fiscal year ended June 30, 2005 are as follows:

	Years Ended December 31,		Six Months Ended December 31,	Year Ended June 30,
	2007	2006	2005	2005
	(In thousands)			
Beginning of the year	$ 483,234	$ 749,624	$ 517,370	$ 288,037
Sales of oil and gas production during the period, net of production costs	(95,976)	(98,340)	(47,746)	(68,602)
Purchase of reserves in place	38,364	14,716	58,790	201,693
Net change in prices and production costs	286,255	(567,435)	170,831	90,938
Changes in estimated future development costs	(106,678)	(35,041)	(50,676)	19,345
Extensions, discoveries and improved recovery	135,868	213,741	336,920	93,624
Revisions of previous quantity estimates, estimated timing of development and other	(83,240)	(82,456)	(164,632)	(91,002)
Previously estimated development and abandonment costs incurred during the period	144,156	46,144	32,280	72,413
Sales of reserves in place	(77,631)	(55,640)	(56,276)	(42,508)
Change in future income tax	(70,801)	222,959	(98,974)	(75,371)
Accretion of discount	48,323	74,962	51,737	28,803
End of year	$ 701,874	$ 483,234	$ 749,624	$ 517,370

(18) Subsequent Events

In early February, the Company added CIG collars for 10,000 Mmbtu/day with a $6.50 per Mmbtu floor and a $7.70 per Mmbtu ceiling in the second quarter of 2008 and a $6.50 per Mmbtu floor and an $8.15 per Mmbtu ceiling in the third quarter of 2008. The Company also entered into new CIG gas hedges for 35,000 Mmbtu per day for the first quarter of 2009 with a floor price of $7.50 per Mmbtu and a ceiling price of $9.88 per Mmbtu. The fair value of the derivative liability at February 26, 2008 was $15.2 million.

On February 19, 2008, the Company's shareholders approved a transaction between the Company and Tracinda Corporation ("Tracinda") to issue 36.0 million shares of the Company's common stock at $19.00 per share for proceeds of $684.0 million. The transaction closed on February 20, 2008 and a portion of the proceeds was immediately used to pay down to zero all amounts outstanding under the Company's revolving credit facility. As a result of the transaction, Tracinda owns approximately 35% of our outstanding common stock and named two members to our Board of Directors, bringing the Board to 12 members. Tracinda has the right to proportional representation on our Board, and based on their current ownership may add up to three additional members at its discretion in the future. It also has a right to proportional representation on all of our Board committees.

(18) Subsequent Events, Continued

On February 28, 2008, the Company closed a transaction with EnCana Oil & Gas (USA) Inc., ("EnCana") to jointly develop a portion of EnCana's leasehold in the Vega Area of the Piceance Basin. In addition, Delta has acquired over 1,700 drilling locations on approximately 18,250 gross acres with a 95% working interest. The transaction increases the Company's working interest in the North Vega project leasehold to 95% from an average 50%, with additional acquired acreage that includes the Buzzard Creek federal unit (4,300 acres) and approximately 6,000 acres immediately adjacent to the Buzzard Creek Unit. With this agreement, the Company's acreage position in the Vega Area totals over 20,250 net acres. The effective date of the transaction is March 1, 2008. Under terms of the agreement the Company has committed to fund $410.5 million, $110.5 million paid at the closing and three $100 million installments over the next four years that have been guaranteed with a Letter of Credit.

DELTA PETROLEUM CORPORATION
RECONCILIATION OF DISCRETIONARY CASH FLOW AND EBITDAX
(in thousands)
(unaudited)

THREE MONTHS ENDED:	December 31, 2007	December 31, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 55,251	$ 25,162
Changes in assets and liabilities	(35,654)	(15,125)
Exploration and dry hole costs	2,924	3,979
Discretionary Cash Flow*	$ 22,521	$ 14,016

TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 84,392	$ 53,386
Changes in assets and liabilities	(19,486)	(1,336)
Exploration and dry hole costs	10,055	8,475
Discretionary Cash Flow*	$ 74,961	$ 60,525

* Discretionary cash flow represents net cash provided by operating activities before changes in assets and liabilities plus exploration costs. Discretionary cash flow is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. Discretionary cash flow is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity.

THREE MONTHS ENDED:	December 31, 2007	December 31, 2006
Net income (loss)	$ (29,980)	$ (10,499)
Income tax expense (benefit)	(2,594)	(6,371)
Interest and financing costs	9,144	7,485
Depletion, depreciation and amortization	26,196	24,009
(Gain) loss on sale of oil and gas properties and other investments	334	(895)
Unrealized (gain) loss on derivative contracts	8,295	(179)
Exploration and dry hole costs	15,157	4,328
EBITDAX**	$ 26,552	$ 17,878

THREE MONTHS ENDED:	December 31, 2007	December 31, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 55,251	$ 25,162
Changes in assets and liabilities	(35,654)	(15,125)
Interest net of financing costs	6,835	6,646
Exploration and dry hole costs	2,924	3,979
Other non-cash items	(2,804)	(2,784)
EBITDAX**	$ 26,552	$ 17,878

TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006
Net income (loss)	$ (149,347)	$ 435
Income tax expense (benefit)	4,113	(502)
Interest and financing costs	27,199	26,316
Depletion, depreciation and amortization	98,415	82,596
(Gain) loss on sale of oil and gas properties and other investments	2,644	(40,643)
Unrealized (gain) loss on derivative contracts	5,816	(12,205)
Exploration and dry hole costs	94,146	20,372
EBITDAX**	$ 82,986	$ 76,369

TWELVE MONTHS ENDED:	December 31, 2007	December 31, 2006
CASH PROVIDED BY OPERATING ACTIVITIES	$ 84,392	$ 53,386
Changes in assets and liabilities	(19,486)	(1,336)
Interest net of financing costs	22,770	23,920
Exploration and dry hole costs	10,055	8,475
Other non-cash items	(14,745)	(8,076)
EBITDAX**	$ 82,986	$ 76,369

** EBITDAX represents net income before income tax expense (benefit), interest and financing costs, depreciation, depletion and amortization expense, gain on sale of oil and gas properties and other investments, unrealized gains (loss) on derivative contracts and exploration and impairment and dry hole costs. EBITDAX is presented as a supplemental financial measurement in the evaluation of our business. We believe that it provides additional information regarding our ability to meet our future debt service, capital expenditures and working capital requirements. This measure is widely used by investors and rating agencies in the valuation, comparison, rating and investment recommendations of companies. EBITDAX is also a financial measurement that, with certain negotiated adjustments, is reported to our lenders pursuant to our bank credit agreement and is used in the financial covenants in our bank credit agreement and our senior note indentures. EBITDAX is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income, income from operations, or cash flow provided by operating activities prepared in accordance with GAAP.

GLOSSARY OF OIL AND GAS TERMS

The terms defined in this section are used throughout this Form 10-K.

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.

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 year ended December 31, 2007 will be provided to holders of the Company's securities at no charge on request by contacting the Company at 303-293-9133, or writing to the attention of the Corporate Secretary at 370 17th Street, Suite 4300, Denver, Colorado 80202.

Officers and Directors

Roger A. Parker
CEO and Chairman of the Board

John R. Wallace
President and COO

Kevin K. Nanke
Treasurer and CFO

Stanley F. Freedman
EVP, General Counsel and Secretary

Outside Directors

Hank Brown
President Emeritus of the University of Colorado

Kevin R. Collins *C*, #, x*
President and CEO of Evergreen Energy, Inc.

Jerrie F. Eckelberger **, C#, x*
Attorney

Aleron H. Larson, Jr.
Private Investor

Russell S. Lewis *, #, x
Senior Vice President of Strategic Development of VeriSign, Inc.

James J. Murren #, x
President and COO of MGM Mirage

Jordan R. Smith *, #, Cx
President of Ramshorn Investments, Inc.

Neal A. Stanley *, #, x
President of Teton Oil & Gas Corporation

Daniel J. Taylor *, x
Executive of Tracinda Corporation

James B. Wallace
Partner - Brownlie, Wallace, Armstrong and Bander Exploration

* *Audit Committee*
\# *Compensation Committee*
x *Nominating & Governance Committee*
C *Committee Chairman*

Corporate Information

Common Stock Listing
Listed on NASDAQ as DPTR

Corporate Offices
Delta Petroleum Corporation
370 17th Street, Suite 4300
Denver, Colorado 80202
(303) 293-9133

Website
www.deltapetro.com

Transfer Agent
Corporate Stock Transfer, Inc.
3200 Cherry Creek Drive South, Suite 430
Denver, Colorado 80209
(303) 282-4800

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

Independent Auditors
KPMG LLP
Denver, Colorado

Investor Relations Contact
Broc Richardson
VP of Corporate Development and IR
investorrelations@deltapetro.com

Annual Meeting
The annual meeting of stockholders of Delta Petroleum Corporation will be held at 10:00 a.m. MDT on May 20, 2008 at the Brown Palace Hotel, 321 17th Street, Denver CO 80202.

Form 10-K
Copies of the Company's Annual Report on Form 10-K may be obtained, without charge, by writing to our corporate secretary at our corporate address or on our website at www.deltapetro.com/corpinfo.aspx

Forward-Looking Statements

Forward-looking statements in this report are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based on management's present expectations, estimates and projections, but involve risks and uncertainty, including without limitation, the availability of capital and the ability to grow reserves, production and cash flow. Please refer to the Company's report on Form 10-K for the year ended December 31, 2007 and subsequent reports on Forms 10-Q and 8-K as filed with the Securities and Exchange Commission for additional information. The Company is under no obligation (and expressly disclaims any obligation) to update or alter its forward-looking statements, whether as a result of new information, future events or otherwise.

DPTR
NASDAQ
LISTED

DELTA

PETROLEUM

CORPORATION

DELTA PETROLEUM CORPORATION
370 17TH STREET, SUITE 4300
DENVER, COLORADO 80202
(303) 293-9133

END