CONCHO RESOURCES INC
Form 10-K
March 28, 2008

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the year ended December 31, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 1-33615
Concho Resources Inc.
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**76-0818600** *(I.R.S. Employer Identification No.)*
550 West Texas Avenue, Suite 1300 **Midland, Texas** *(Address of principal executive offices)*	**79701** *(Zip code)*

(432) 683-7443
(Registrant s telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.001 par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of August 3, 2007, the date our shares began trading on the New York Stock Exchange:	$ 363,717,758
Number of shares of registrant s common stock outstanding as of March 27, 2008:	75,987,562

Documents Incorporated by Reference:

Portions of the registrant s definitive proxy statement for its 2008 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2007, are incorporated by reference into Part III of this annual report for the year ended December 31, 2007.

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Cautionary statement regarding forward-looking statements

This report may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this annual report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this annual report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project ar are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and elsewhere in this annual report could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- estimated quantities of oil and natural gas reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- general economic and business conditions;
- cash flow and anticipated liquidity;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this annual report that are not historical.

You should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this annual report. We do not undertake any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this annual report or to reflect the occurrence of unanticipated events except as required by law.

Although we believe that our plans, objectives, expectations and intentions reflected in or suggested by the forward-looking statements we make in this annual report are reasonable, we can give no assurance that they will be achieved. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

Item 1. *Business*

General

Concho Resources Inc., a Delaware corporation (Concho, Company, we, us and our), is an independent oil and r gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. These conventional operations are complemented by our activities in unconventional emerging resource plays. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

We were formed in February 2006 as a result of the combination of Concho Equity Holdings Corp. (now known as Concho Equity Holdings LLC) and a portion of the oil and natural gas properties and related assets owned by Chase Oil Corporation and certain of its affiliates. Concho Equity Holdings Corp. was formed in April 2004 and represents the third of three Permian Basin-focused companies that have been formed since 1997 by our current management team (the prior two companies were sold to large domestic independent oil and gas companies).

Business and Properties

Our operations are primarily concentrated in the Permian Basin, the largest onshore oil and gas basin in the United States. As of December 31, 2007, 99% of our total estimated net proved reserves were located in the Permian Basin and consisted of approximately 59% crude oil and 41% natural gas. This basin is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. The primary producing formation in the Permian Basin under our core properties in Southeast New Mexico is the Paddock interval of the Yeso formation, which is located at depths ranging from 3,800 feet to 5,800 feet. We have also discovered reserves and are producing oil and natural gas from the Blinebry interval of the Yeso formation, the top of which is located approximately 400 feet below the base of the Paddock interval. In addition, we have assembled a multi-year inventory of development drilling and exploitation projects, including projects to further evaluate the aerial extent of the Yeso formation, that we believe will allow us to grow proved reserves and production. We have also acquired significant acreage positions in the Permian Basin of Southeast New Mexico, the Central Basin Platform and the Delaware Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas covering unconventional emerging resource plays, where we intend to apply horizontal drilling and advanced fracture stimulation technologies.

We drilled, or participated in the drilling of, 117 gross (87.7 net) wells in 2007, 85% of which were completed as producers, 2% of which were dry holes and 13% of which were awaiting completion as of December 31, 2007. In addition, in 2007, we recompleted, or participated in the recompletion of, 132 gross (107.8 net) wells, 95% of which were productive. As a result, we increased our total estimated net proved reserves by approximately 79 Bcfe from 467 Bcfe as of December 31, 2006 to 546 Bcfe as of December 31, 2007, while producing approximately 30 Bcfe of oil and natural gas during the year ended December 31, 2007. In addition, we increased our average net daily production from 80 MMcfe per day during the first quarter of 2007 to 91 MMcfe per day during the fourth quarter of 2007.

An unconventional emerging resource play generally consists of a large area that, based on its geological and geophysical characteristics, indicates the possible existence of a continuous accumulation of hydrocarbons. These plays are typically associated with tight, fractured rocks, such as fractured shales, fractured carbonates, coal seams and tight sands, which may serve as the source of the hydrocarbons and as the productive reservoir. In our unconventional emerging resource plays, we target areas where we can acquire large undeveloped acreage positions and apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies to achieve economic, repeatable production results. As of December 31, 2007, we held interests in 206,791 gross (94,169 net) acres in five unconventional emerging resource plays. Our positions include acreage in:

the Northwest Shelf area of Southeast New Mexico, where we have tested one re-entry well and drilled sixteen wells targeting the Wolfcamp Carbonate;

the Central Basin Platform of West Texas, where we have drilled a test well in the Woodford Shale and are waiting on completion;

the Western Delaware Basin of West Texas, where we have drilled four exploratory wells targeting the Bone Spring, Atoka, Barnett and Woodford Shales;

the North Dakota portion of the Williston Basin, where we have participated in the drilling of eight wells targeting the Bakken Shale with four producing, three waiting on completion and one drilling at December 31, 2007; and

the eastern Arkoma Basin in Arkansas, where we plan to drill our first test well in 2008, which will target the Fayetteville Shale.

Our exploration and development budget for the year ending December 31, 2008 is approximately $250 million. We plan to spend approximately 92% of our exploration and development budget on exploration and development activities associated with our conventional properties in the Permian Basin, 2% for leasehold acquisitions and 6% for exploration activities in our unconventional emerging resource plays. If we believe circumstances merit such action, including successful results from exploratory drilling in our unconventional emerging resource plays, we may reallocate or increase our 2008 exploration and development budget.

Combination Transaction

On February 24, 2006, we entered into a combination agreement in which we agreed to purchase certain oil and gas properties owned by Chase Oil Corporation (Chase Oil), Caza Energy LLC and certain other working interest owners (which we refer to collectively as the Chase Group) and combine them with substantially all of the outstanding equity interests of Concho Equity Holdings Corp. to form our company. The initial closing of the transactions contemplated by the combination agreement occurred on February 27, 2006, and the members of the Chase Group that sold their working interests to us received 34,683,315 shares of our common stock and approximately $400 million in cash, and the former shareholders of Concho Equity Holdings Corp. that were a party to the combination agreement received 23,767,691 shares of our common stock. In addition, certain options held by our employees to purchase preferred and common stock of Concho Equity Holdings Corp. were converted into options to purchase 2,349,113 shares of our common stock. The oil and gas properties contributed to us by the Chase Group (which we refer to as the Chase Group Properties) represented approximately 81% of our PV-10 as of December 31, 2007. The executive officers of Concho Equity Holdings Corp. became the executive officers of our company at the closing of the combination transaction. We have accounted for the combination transaction as a reorganization of our company, such that Concho Equity Holdings Corp. is now our wholly owned subsidiary, and a simultaneous acquisition by our company of the assets contributed by the Chase Group.

Drilling Activities

The following table sets forth information with respect to wells drilled during the periods indicated and does not include wells drilled on the oil and gas properties we acquired from the Chase Group prior to the combination

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transaction. This information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development wells						
Productive	60.0	38.5	93.0	57.8	61.0	23.5
Dry			7.0	2.4	3.0	1.7
Exploratory wells						
Productive	55.0	48.0	37.0	25.4	8.0	2.2
Dry	2.0	1.2	3.0	0.8	3.0	1.4
Total wells						
Productive	115.0(a)	86.5	130.0	83.2	69.0	25.7
Dry	2.0	1.2	10.0	3.2	6.0	3.1
Total	117.0	87.7	140.0	86.4	75.0	28.8

(a) Of the 115.0 gross productive wells drilled in 2007, 15.0 were still in the process of being completed as of December 31, 2007.

As of December 31, 2007, we had 8 gross (6.4 net) wells that were in the process of being drilled, 3 of which were development wells and 5 of which were exploratory wells.

We determined in January 2007 to reduce our drilling activities for the three months ended March 31, 2007. This determination was due to a decline in oil and natural gas prices in January 2007 compared to such prices in the fourth quarter of 2006, the costs of goods and services necessary for our drilling activities and the resulting effect of these circumstances on our expected cash flow for the three months ended March 31, 2007. This reduction in drilling activities resulted in a reduction in oil and gas production, revenues and cash provided by operating activities for the year ended December 31, 2007. We resumed our drilling activities in April 2007, and we expended our approved 2007 exploration and development budget of approximately $183 million before January 1, 2008.

Our Production, Prices and Expenses

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2007, 2006 and 2005. The actual historical data in this table excludes production and related sales prices and costs attributable to the Chase Group Properties for periods prior to February 27, 2006.

	Years Ended December 31,		
	2007	2006	2005
Net production volumes:			
Oil (MBbl)	3,014.0	2,294.8	599.0

Natural gas (MMcf)	12,064.0	9,506.8	3,403.8
Natural gas equivalent (MMcfe)	30,147.8	23,275.4	6,997.7

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	December 31, 2007	December 31, 2006	December 31, 2005
Average prices:			
Oil, without hedges ($/Bbl)	$ 68.58	$ 60.47	$ 54.71
Oil, with hedges ($/Bbl)	$ 64.90	$ 57.42	$ 52.79
Natural gas, without hedges ($/Mcf)	$ 8.08	$ 6.87	$ 6.99
Natural gas, with hedges ($/Mcf)	$ 8.18	$ 7.00	$ 6.85
Natural gas equivalent, without hedges ($/Mcfe)	$ 10.09	$ 8.77	$ 8.08
Natural gas equivalent, with hedges ($/Mcfe)	$ 9.76	$ 8.52	$ 7.85
Operating costs and expenses:			
Oil and gas production ($/Mcfe)	$ 0.99	$ 0.95	$ 1.56
Oil and gas production taxes ($/Mcfe)	$ 0.81	$ 0.68	$ 0.53
General and administrative ($/Mcfe)	$ 0.71	$ 0.54	$ 1.15
Depreciation and depletion expense ($/Mcfe)	$ 2.55	$ 2.61	$ 1.64

Summary of Core Operating Areas and Emerging Resource Plays

Permian Basin

The Permian Basin is one of the most prolific oil and gas regions in the United States, with its first commercial discovery in 1923 and cumulative production of 32.8 billion barrels of oil and 107 trillion cubic feet of gas as of December 31, 2007. Average daily production in the Permian Basin is approximately 11 billion cubic feet equivalent gas per day from approximately 121,500 active producing wells. It underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from approximately 1,000 feet to over 25,000 feet. This area is characterized by long life shallow decline reserves.

The Permian Basin is our core operating area, and, as of December 31, 2007, our estimated net proved reserves of 541 Bcfe in this basin accounted for 99% of our total estimated net proved reserves and 99% of our PV-10. As of December 31, 2007, we owned interests in 2,013 wells in the Permian Basin, of which we operated 1,029. Based on our total proved reserves as of December 31, 2007, and our 2007 production, our reserve to production ratio was 18.2 years. As of December 31, 2007, we had identified 1,653 drilling locations, with proved undeveloped reserves attributed to 623 of such locations, and 874 recompletion opportunities, with proved reserves attributed to 372 of such opportunities. During the year ended December 31, 2007, our average net daily production in the Permian Basin was 81.4 MMcfe per day.

Southeast New Mexico Permian

Our Permian Basin operations in Southeast New Mexico represent our most significant concentration of assets and, as of December 31, 2007, our estimated proved reserves of 460.8 Bcfe in this portion of the Permian Basin accounted for 84% of our total net proved reserves and 85% of our proved PV-10. As of December 31, 2007, the wells that we operated accounted for 92% of our proved PV-10 in this core area. As of December 31, 2007, we had 1,518 producing wells in Southeast New Mexico. During the year ended December 31, 2007, our average net daily production from this area was approximately 66.4 MMcfe per day, representing 80% of our total production for that time period. We target two distinct producing areas, which we refer to herein as the Shelf Properties and the Basinal Properties. The Shelf Properties generally produce from the Yeso (Paddock and Blinebry intervals), San Andres and Grayburg formations, with producing depths generally ranging from 900 feet to 7,500 feet. The Basinal Properties generally produce from the Morrow formation, with producing depths generally ranging from 7,500 feet to 15,000 feet.

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Shelf Properties

Our Shelf Properties represented 81% of our total PV-10 as of December 31, 2007. We acquired most of these properties from the Chase Group upon closing the combination transaction. As of December 31, 2007, we had 429.4 Bcfe of proved reserves and 1,243 producing wells in this area. As of December 31, 2007, we held interests in 100,603 gross (49,306 net) acres in this area. As of December 31, 2007, on our Shelf Properties, we had identified 1,368 drilling locations, with proved undeveloped reserves attributed to 432 of such locations, and 783 recompletion opportunities, with proved undeveloped reserves attributed to 297 of such opportunities. Average net daily production from this area for the year ended December 31, 2007, was approximately 58.5 MMcfe per day, and production from this area represented 71% of our total average daily net production for the same period. Our properties in this area are primarily located in Eddy and Lea Counties, New Mexico, along the Abo-Yeso shelf edge on the northern rim of the Delaware Basin. This east to west trending fairway produces from a succession of stacked pays. During 2007, we continued our development of the Blinebry interval of the Yeso formation, the top of which is located approximately 400 feet below the base of the Paddock interval of the Yeso formation. Our evaluation of the Blinebry interval began in late 2005. In 2007, we drilled 83 wells in the Blinebry interval, all of which have since been completed as producers. As of December 31, 2007, we were operating 5 drilling rigs on our Shelf Properties, all of which were targeting the Blinebry.

Included in the drilling locations we had identified as of December 31, 2007 were 672 drilling locations in the Blinebry interval, with proved undeveloped reserves attributed to 134 of such locations. Of the remaining locations, 446 of such locations are intended to evaluate both the Blinebry and the Paddock intervals, while 92 of such locations are intended to evaluate just the Blinebry interval. During the year ended December 31, 2007, we drilled 83 Blinebry wells, of which 74 were completed as producers and 9 were awaiting completion as of December 31, 2007. In addition, in September 2007 we began injecting water on our pilot waterflood covering approximately 160 acres in the Paddock interval of the Yeso formation. The Empire/Empire East and Loco Hills fields collectively comprised 74% of our Southeast New Mexico PV-10 as of December 31, 2007.

Empire/Empire East Field. We are currently producing from the Yates, Morrow, Grayburg, Queen, Strawn, Wolfcamp, Seven Rivers, Yeso (Paddock and Blinebry intervals) and Abo formations. As of December 31, 2007, we had 201 Bcfe of proved reserves and 623 wells producing in the area. In addition, as of December 31, 2007, we had identified 368 drilling locations, with proved undeveloped reserves attributed to 161 of such locations, and 341 recompletion opportunities, with proved undeveloped reserves attributed to 117 of such opportunities. As of December 31, 2007, proved reserves attributable to the Empire/Empire East field had a PV-10 of $857.2 million, which represented approximately 47% of the total PV-10 attributable to our Southeast New Mexico properties. Average net daily production from this field for the year ended December 31, 2007 was approximately 25.5 MMcfe per day.

Loco Hills Field. We are currently producing from the Seven Rivers, Queen, Grayburg, Morrow, Abo, San Andres and Yeso (Paddock and Blinebry intervals) formations. As of December 31, 2007, we had 254 producing wells in this field. In addition, as of December 31, 2007, we had identified 199 drilling locations, with proved undeveloped reserves attributed to 91 of such locations, and 291 recompletion opportunities, with proved reserves attributed to 112 of such opportunities. As of December 31, 2007, proved reserves attributable to the Loco Hills field had a PV-10 of $496.5 million, which represented approximately 27% of the total PV-10 attributable to our Southeast New Mexico properties. Average net daily production from this field for the year ended December 31, 2007 was approximately 21.2 MMcfe per day.

Basinal Properties

Our Basinal Properties in Southeast New Mexico represented approximately 4% of our total PV-10 as of December 31, 2007. As of December 31, 2007, we had 31 Bcfe of proved reserves and 275 wells in this area. As of December 31, 2007, we held interests in 68,708 gross (25,576 net) acres in this area. As of December 31, 2007, on our Basinal Properties, we had identified 98 drilling locations, with proved undeveloped reserves attributed to 58 of such locations, and 39 recompletion opportunities, with proved undeveloped reserves attributed to 34 of such opportunities. Average net daily production from this area for the year ended December 31, 2007, was approximately 7.9 MMcfe per day, and production from this area represented 10% of our total average daily net production for the same period. The majority of our production in this region is from the Morrow formation, with significant additional contributions from the more shallow Atoka and Strawn formations. During the year ended December 31, 2007, we drilled 4 wells to the Morrow formation, of which 3 were completed as producers and 1 was a dry hole. In addition, during the year ended December 31, 2007, we recompleted 5 wells in the Morrow formation, all of which were producing as of December 31, 2007.

Texas Permian

This area accounted for approximately 14% of our total proved reserves and approximately 13% of our total PV-10 as of December 31, 2007. As of December 31, 2007, we had 75 Bcfe of proved reserves and 491 wells producing in this area. In addition, as of December 31, 2007, we had identified 143 drilling locations, with proved undeveloped reserves attributed to 124 of such locations, and 52 recompletion opportunities, with proved undeveloped reserves attributed to 41 of such opportunities. During the year ended December 31, 2007, we drilled 9 wells, all of which were completed as producers as of December 31, 2007. In addition, during the year ended December 31, 2007, we commenced the recompletion of 19 wells, all of which were producing as of December 31, 2007.

Emerging Resource Plays

As of December 31, 2007, we were involved in 5 unconventional emerging resource plays, with interests in 206,791 gross (94,169 net) acres. These plays are currently in various stages of maturity. As of December 31, 2007, we had an aggregate of 6.4 Bcfe of proved reserves attributed to these plays.

Southeast New Mexico

Horizontal Wolfcamp gas and oil plays are being actively exploited along the northwestern rim of the Delaware Basin in Eddy and Chaves Counties, New Mexico, with several operators producing and selling oil and gas. As of December 31, 2007, we held interests in 55,668 gross (23,699 net) acres in these plays.

The horizontal Wolfcamp gas play is found at depths ranging from 4,100 feet to 6,000 feet. Of our horizontal Wolfcamp acreage, 38,136 gross (10,064 net) acres are in the Wolfcamp gas play. We have tested 1 re-entry well, and have participated in the drilling of 13 horizontal exploration wells in this play.

The horizontal Wolfcamp oil play is found at depths ranging from 6,500 feet to 9,000 feet. Of our horizontal Wolfcamp acreage, 17,532 gross (13,635 net) acres are in the horizontal Wolfcamp oil play. We have drilled 3 wells in the oil play, 2 of which were completed as horizontal Wolfcamp oil producers, and 1 of which was completed as a vertical producer in a shallower interval.

As of December 31, 2007, we had 6.0 Bcfe of proved reserves attributed to the horizontal Wolfcamp gas and oil plays.

Central Basin Platform of West Texas

As of December 31, 2007, we held interests in 22,925 gross (22,155 net) acres in an unconventional shale play in Andrews County, Texas. This unconventional shale is prospective at depths of 8,000 to 10,000 feet. We drilled our first test well in the first quarter of 2008, and it is currently awaiting completion.

Western Delaware Basin of West Texas

The Delaware Basin shale play is located in West Texas in a lightly explored portion of the Delaware Basin. As of December 31, 2007, we held interests in 68,814 gross (22,794 net) acres in Culberson and Reeves Counties, Texas.

Both conventional and unconventional targets are prospective in this area. We have drilled 4 exploratory wells targeting the Bone Spring, Atoka, Barnett and Woodford Shales, which are found at depths ranging from 5,000 feet to 12,000 feet. Three of these wells have been deemed non-commercial. A vertical Woodford Shale completion in the fourth well tested at a rate of approximately 1 MMcf per day, and is currently flowing gas to sales at a rate of approximately 650 Mcf per day.

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North Dakota

The horizontal Bakken Shale play is being developed in the North Dakota portion of the Williston Basin. This Mississippian age horizon consists of a siltstone encased within a highly organic, oil-rich shale package and is found at depths ranging from 9,000 feet to 11,000 feet. As of December 31, 2007, we had participated in 8 horizontal Bakken wells, of which 4 were producing, 3 were awaiting completion and 1 was drilling. As of December 31, 2007, we held interests in 42,362 gross (11,069 net) acres in this play, primarily in Mountrail and McKenzie Counties, North Dakota. As of December 31, 2007, we had 0.4 Bcfe of proved reserves attributed to this play.

Arkansas

As of December 31, 2007, we held interests in 17,022 gross (14,452 net) acres in the Fayetteville Shale play in Faulkner and White Counties, Arkansas. The Fayetteville Shale play in the eastern Arkoma Basin of Arkansas is the geological time equivalent to the Barnett Shale, a productive horizon in the Ft. Worth Basin. The Fayetteville Shale has production from both vertical and horizontal wells, and on our acreage position the Fayetteville Shale is found at depths ranging from 7,000 feet to 8,500 feet. We plan on drilling our initial test well in this area in 2008.

Marketing Arrangements

General. We market our crude oil and natural gas in accordance with standard energy practices utilizing certain of our employees and independent consultants, in each case in consultation with our chief financial officer and our production engineers. The marketing effort is coordinated with our operations group as it relates to the planning and preparation of future drilling programs so that available markets can be assessed and secured. This planning also involves the coordination of procuring the physical facilities necessary to connect new producing wells as efficiently as possible upon their completion. When possible, we negotiate with our purchasers on multiple well programs in an attempt to improve our economics on such wells due to the commitment of potentially increased production volumes. Our current drilling plans consist substantially of multiple well programs.

Crude Oil. We do not refine or process the crude oil we produce. The majority of our crude oil is connected directly to pipelines via gathering facilities in the respective field locations throughout Southeast New Mexico and West Texas. The oil is then delivered either to hub facilities located in Midland, Texas or Cushing, Oklahoma or to third party refineries located in Southeast New Mexico and the panhandle of Texas, with the majority of our crude oil going to a refinery in Southeast New Mexico. The remaining oil that we produce is transported by truck to various pipeline stations throughout Southeast New Mexico and West Texas. This oil is also transported to the hub facilities and refineries mentioned above. We sell the majority of the oil we produce under short-term contracts using market sensitive pricing. The majority of our contracts are based on a Platt s formula which is calculated based on an intermediate posting deemed 40 degrees (typically as published by major crude oil purchasers at the Cushing, Oklahoma delivery point) for each calendar month plus the average of the Platt s P-Plus WTI price as published monthly in the Platt s Oilgram Price Report. This price is then adjusted for differentials based upon delivery location and oil quality.

Natural Gas. When assessing the market for our natural gas we first determine the type of gas connection needed based upon the type of gas expected to be produced. We also consider any gas gathering and delivery infrastructure in the areas of our production and evaluate market options to obtain the best price reasonably available under the circumstances. We sell the majority of our gas under individually negotiated gas purchase contracts using market sensitive pricing. The majority of our gas is subject to term agreements that extend at least three years from the date of the subject contract.

The majority of the gas we sell is casinghead gas which is sold at the wellhead under a percentage of proceeds processing contract. The purchaser gathers our casinghead gas in the field where produced and transports it via pipeline to a gas processing plant where the liquid products are extracted. The remaining gas product is residue gas, or dry gas. Under our percentage of proceeds contract, we receive the value for the extracted liquids and the residue gas. Each of the liquid products has its own individual market and is therefore priced separately.

The remaining portion of our gas is dry gas which is gathered at the wellhead and delivered into the purchaser s residue or mainline transportation system. In many cases, the gas gathering and transportation is performed by a third party gathering company which transports the production from the production location to the purchaser s mainline. The majority of our dry gas and residue gas is subject to term agreements that extend at least three years from the date of the subject contract.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, see Item 1A. Risk Factors Risks Relating to Our Business Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

For the year ended December 31, 2007, revenues from oil and natural gas sales to Navajo Refining Company, L.P. and DCP Midstream, LP, formerly Duke Energy Field Services, accounted for approximately 60% and 23%, respectively, of our total operating revenues. While the loss of either of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of either of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the regions in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated oil companies. We primarily encounter significant competition in acquiring properties, contracting for drilling and workover equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay developmental drilling, workover and exploitation activities and cause significant price increases. The current shortage of personnel has also made it difficult to attract and retain personnel with experience in the oil and gas industry and has caused us to increase our general and administrative budget. We are unable to predict the nature, timing or duration of any such shortages.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily. Although we regularly evaluate acquisition opportunities and submit bids as part of our growth strategy, we do not have any current agreements, understandings or arrangements with respect to any material acquisition.

Applicable Laws and Regulations

Regulation of the Oil and Natural Gas Industry

Regulation of transportation of oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be just and reasonable based on cost, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system that enables interstate oil pipelines to change their rates within prescribed ceiling levels that are tied to an inflation index. The FERC s indexing methodology is subject to review every five years; the current methodology is expected to remain in place through June 30, 2011. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of transportation and sale of natural gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Production. The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production, and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA , and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA , the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA , also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act , and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Air Emissions. The federal Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

In response to recent studies suggesting that emissions of certain gases, referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere, the current session of the U.S. Congress is considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. The Lieberman-Warner bill proposes a cap and trade scheme of regulation of greenhouse gas emissions a ban on emissions above a defined reducing annual cap. Covered parties will be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. Debate and a possible vote on this bill by the full Senate are anticipated to occur before mid-year 2008. In addition, at least one-third of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels we produce.

Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA,* and certain provisions of the Clean Air Act, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has publicly stated its goal of issuing a proposed rule to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels but the timing for issuance of this proposed rule is unsettled as the agency reviews its mandates under the Energy Independence and Security Act of 2007, which includes expanding the use of renewable fuels and raising the corporate average fuel economy standards. The Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New federal or state laws requiring adoption of a stringent greenhouse gas control program or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for our products.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

OSHA and Other Laws and Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA , and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2007. Additionally, as of the date of this annual report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2008. However, we cannot assure you that the passage of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operation. For instance, the New Mexico Oil Conservation Division is considering amending or replacing an existing rule regulating the permitting, construction, operation and closure of oilfield pits at well sites in New Mexico. If the agency adopts a new or revised pit rule that imposes stricter requirements on the construction and use of oilfield pits, then it is possible that the cost to operate our wells in New Mexico could increase.

Our Employees

As of December 31, 2007, we employed 113 employees, including 44 in drilling and production, 16 in financial and accounting, 20 in land, 14 in exploration, 7 in reservoir engineering and 12 in administration. Of these, 86 worked in our Midland, Texas headquarters and 27 were in our field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We also utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the Securities and Exchange Commission (the SEC) under the Securities Exchange Act of 1934 (the Exchange Act). The public may read and copy any materials that we file with or furnish to the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including Concho, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at http://www.sec.gov.

We also make available free of charge through our internet website (www.conchoresources.com) our annual report, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A. *Risk Factors*

You should carefully consider the risk factors set forth below as well as the other information contained in this annual report. Any of the following risks could materially and adversely affect our business, financial condition or results of operations. In such case, you may lose all or part of your investment. The risks described below are not the only risks facing us. Additional risks and uncertainties not currently known to us or those we currently view to be immaterial may also materially adversely affect our business, financial condition or results of operations.

Risks Relating to Our Business

Oil and natural gas prices are volatile. A decline in oil and natural gas prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of our cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil and natural gas are subject to a variety of factors, including:

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxes;

the price and availability of alternative fuel sources;

weather conditions;

political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;

technological advances affecting energy consumption; and

worldwide economic conditions.

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Declines in oil and natural gas prices would not only reduce our revenue, but could reduce the amount of oil and natural gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can affect the value of our common stock.

Furthermore, recent oil prices have been high compared to historical prices and have been particularly volatile. For example, the NYMEX crude oil price per Bbl was $95.98, $61.15 and $61.04 as of December 31, 2007, 2006 and 2005, respectively. In addition, natural gas prices have been subject to significant fluctuations during the past several years. For example, the NYMEX natural gas Henry Hub spot price per MMbtu was $6.80, $5.64 and $10.08 as of December 31, 2007, 2006 and 2005, respectively.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our expenses to increase or our cash flows and production volumes to decrease.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- surface access restrictions;
- title problems; and
- limitations in the market for oil and natural gas.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the estimated quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many estimates, including estimates based upon assumptions relating to economic factors. Any significant inaccuracies in these interpretations or estimates could materially reduce the estimated quantities and present value of reserves shown in this annual report. See Item 2. Properties Our Oil and Natural Gas Reserves for information about our oil and natural gas reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, the amount and timing of capital expenditures, taxes and the availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this annual report. For example, in connection with the preparation of our total estimated net proved reserves as of December 31, 2007, we revised our estimated natural gas equivalent reserves downward by 19,168 MMcfe from our previous estimates. This reduction in reserves was primarily due to reduction in forecasted future performance and other revisions to proved properties existing at December 31, 2006, conversion of producing wells to water injection wells on a pilot waterflood on our Shelf Properties, and dry holes drilled during 2007. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

It should not be assumed that the present value of future net revenues from our proved reserves referred to in this annual report is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2007 referred to in this annual report was based on a $92.50 per Bbl Plains Marketing, L.P. West Texas Intermediate posted price for oil and a $6.80 per MMBtu Henry Hub spot price for natural gas. If oil prices were $1.00 per Bbl lower than the price we used, our PV-10 as of December 31, 2007, would have decreased from $2,138.5 million to $2,116.1 million. If natural gas prices were $0.10 per Mcf lower than the price we used, our PV-10 as of December 31, 2007, would have decreased from $2,138.5 million to $2,127.7 million. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our common stock.

Almost all of our producing properties are located in the Permian Basin region of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, a substantial portion of our proved reserves as of December 31, 2007, are from a single producing horizon within this area.

Our producing properties are geographically concentrated in the Permian Basin region of Southeast New Mexico and West Texas. At December 31, 2007, approximately 99% of our PV-10 was attributable to properties located in the Permian Basin. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from these wells caused by significant governmental regulation, processing or transportation capacity constraints, market limitations, curtailment of production or interruption of the processing or transportation of oil and natural gas produced from the wells in these areas.

In addition to the geographic concentration of our producing properties described above, approximately 58% of our proved reserves as of December 31, 2007, were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and gas properties located in Southeast New Mexico. This concentration of assets within one producing horizon exposes us to risks such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within the field. Furthermore, we are in the process of drilling and completing wells in the Blinebry interval (the lower member of the Yeso formation), which lies beneath the Paddock interval on certain of our properties located in Southeast New Mexico. These activities could result in delays in the production of our proved reserves from the Paddock interval in the event that commingling of both formations is imprudent or otherwise not feasible.

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Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

The results of our exploratory drilling in new or emerging areas are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparty.

Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. As of December 31, 2007, the net unrealized loss on our commodity price risk management contracts was approximately $45.1 million. An average increase in the commodity price of $1.00 per barrel of crude oil and $0.10 per Mcf for natural gas from the commodity prices as of December 31, 2007 would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet as of December 31, 2007, of approximately $2.7 million. We may continue to incur significant unrealized losses in the future from our commodity price risk management activities to the extent market prices continue to increase and our derivatives contracts remain in place. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Commodity Derivatives and Hedging.

If we enter into derivative instruments that require us to post cash collateral, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures. Future collateral requirements will depend on arrangements with our counterparties and highly volatile oil and natural gas prices.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the acquisition, exploration and development of oil and natural gas reserves. For example, during the first three months of 2007, we curtailed our drilling program in order to preserve liquidity until we could complete our second lien term loan facility. As of December 31, 2007, our total debt outstanding was $327.4 million, and $209.0 million was available to be borrowed under our revolving credit facility. Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We invested approximately $183 million in 2007 and anticipate investing approximately $250 million in 2008 for acquisition, exploration and development activities on our properties. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Future Capital Expenditures and Commitments.

We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of outstanding common stock. Additional borrowings under our revolving credit facility or the issuance of additional debt will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our bank credit facilities impose certain limitations on our ability to incur additional indebtedness other than indebtedness under our revolving credit facility. If we desire to issue additional debt securities other than as expressly permitted under our bank credit facilities, we will be required to seek the consent of the lenders in accordance with the requirements of those facilities, which consent may be withheld by the lenders under our bank credit facilities in their discretion. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing to satisfy our capital requirements. If cash generated from operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition or results of operations.

Our identified inventory of drilling locations and recompletion opportunities are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled the drilling and recompletion of our drilling and recompletion opportunities as an estimation of our future multi-year development activities on our existing acreage. As of December 31, 2007, we had identified 1,659 drilling locations with proved undeveloped reserves attributable to 627 of such locations, and 878 recompletion opportunities with proved undeveloped reserves attributed to 375 of such opportunities. These identified opportunities represent a significant part of our growth strategy. Our ability to drill and develop these opportunities depends on a number of uncertainties, including the availability of capital, equipment, services and personnel, seasonal conditions, regulatory and third party approvals, oil and natural gas prices, costs and drilling and recompletion results. Because of these uncertainties, we may never drill or recomplete the numerous potential opportunities we have identified or produce oil or natural gas from these or any other potential opportunities. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our business.

Approximately 46% of our total estimated net proved reserves as of December 31, 2007, were undeveloped, and those reserves may not ultimately be developed.

As of December 31, 2007, approximately 46% of our total estimated net proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. If we choose not to spend the capital to develop these reserves, or if we are not able to successfully develop these reserves, we will be required to write-off these reserves. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our common stock.

Because we do not control the development of the properties in which we own interests, but do not operate, we may not be able to achieve any production from these properties in a timely manner.

As of December 31, 2007, approximately 10% of our PV-10 was attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on such nonoperated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators expertise and financial resources;
- the approval of other participants in such properties; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines, which may adversely affect our production, revenues and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our common stock.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our common stock and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

We may be unable to make attractive acquisitions or integrate acquired companies, and any inability to do so may disrupt our business and hinder our ability to grow through the acquisition of businesses.

One aspect of our business strategy calls for acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities.

Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our bank credit facilities impose certain direct limitations on our ability to enter into mergers or combination transactions involving our company. Our bank credit facilities also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses. If we desire to engage in an acquisition that is otherwise prohibited by our bank credit facilities, we will be required to seek the consent of the lenders in accordance with the requirements of those facilities, which consent may be withheld by the lenders under our bank credit facilities in their discretion.

If we acquire another business, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Properties acquired may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

We obtained the majority of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and increased compensation for trained personnel could have a material adverse effect on our business.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, or shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;

- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;

- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our business, financial condition or results of operations.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipeline or gathering system or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations.

Our oil and natural gas exploration, development and production, and saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, the New Mexico Oil Conservation Division is considering amending or replacing an existing rule regulating the permitting, construction, operation and closure of oilfield pits at well sites in New Mexico. If the agency adopts a new or revised pit rule that imposes stricter requirements on the construction and use of oilfield pits, then it is possible that the cost to operate our wells in New Mexico could increase. These and other future costs could have a material adverse effect on our business, financial condition or results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition or results of operations. See Item 1. Business Applicable Laws and Regulations for a description of certain laws and regulations that affect us.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, development and production, and saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected. See Item 1. Business Applicable Laws and Regulations Environmental, Health and Safety Matters for more information.

The loss of our chief executive officer or our chief operating officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of Timothy A. Leach, our chairman of the board and chief executive officer, Steven L. Beal, our president and chief operating officer, our other executive officers and our key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on the investments we make to use such methods.

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on the investments we make to use such methods.

Our indebtedness could restrict our operations and make us more vulnerable to adverse economic conditions.

We now have, and will continue to have, a significant amount of indebtedness, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. As of December 31, 2007, our total debt was $327.4 million. At December 31, 2007, our revolving credit facility bore interest at a rate of 6.16% per annum and our second lien term loan facility bore interest at 9.23% per annum. Assuming our total debt outstanding as of December 31, 2007 was held constant throughout the year, if interest rates had been higher or lower by 1% per annum, interest expense for the year ended December 31, 2007 would have increased or decreased by approximately $3.3 million. As of December 31, 2007, our total borrowing capacity under our revolving credit facility was $425.0 million, of which $209.0 million was available.

Our current and future indebtedness could have important consequences to you. For example, it could:

impair our ability to make investments and obtain additional financing for working capital, capital expenditures, acquisitions or other general corporate purposes;

limit our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make principal and interest payments on our indebtedness;

limit our ability to borrow funds that may be necessary to operate or expand our business;

- put us at a competitive disadvantage to competitors that have less debt;
- increase our vulnerability to interest rate increases; and
- hinder our ability to adjust to rapidly changing economic and industry conditions.

Our ability to meet our debt service and other obligations may depend in significant part on the extent to which we can successfully implement our business strategy. We may not be able to implement or realize the benefits of our business strategy.

Our existing bank credit facilities impose restrictions on us that may affect our ability to successfully operate our business.

Our bank credit facilities limit our ability to take various actions, such as:

- incurring additional indebtedness;
- paying dividends;
- creating certain additional liens on our assets;
- entering into sale and leaseback transactions;
- making investments;
- entering into transactions with affiliates;
- making material changes to the type of business we conduct or our business structure;
- making guarantees;
- disposing of assets in excess of certain permitted amounts;
- merging or consolidating with other entities; and
- selling all or substantially all of our assets.

In addition, our bank credit facilities require us to maintain certain financial ratios and to satisfy certain financial conditions, which may require us to reduce our debt or take some other action in order to comply with each of them.

These restrictions could also limit our ability to obtain future financings, make needed capital expenditures, withstand a downturn in our business or the economy in general, or otherwise conduct necessary corporate activities. We also may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under each of our bank credit facilities.

A terrorist attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities we use for the production, transportation or marketing of our oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Relating to Our Common Stock

Our certificate of incorporation, bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 662/3% of the voting power of all outstanding voting stock;
- the prohibition of stockholder action by written consent; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Because we have no plans to pay dividends on our common stock, stockholders must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. The terms of our existing bank credit facilities restrict the payment of dividends without the prior written consent of the lenders. Stockholders must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions, the payment of our indebtedness or other purposes. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into our common stock. Any of these events may dilute your ownership interest in our company and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Item 1B. *Unresolved Staff Comments*

None.

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Item 2. *Properties*

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2007:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin:						
Southeast New Mexico	108,968	54,208	60,343	20,674	169,311	74,882
West Texas	76,505	25,423	14,842	8,856	91,347	34,279
Emerging Plays and Other(1)	18,858	7,787	227,601	114,956	246,459	122,743
Total	204,331	87,418	302,786	144,486	507,117	231,904

(1) The following table sets forth gross and net acreage as of December 31, 2007 for each of our five emerging resource plays and our acreage categorized as Other included in Emerging Plays and Other.

	Total Acres	
	Gross	Net
Southeast New Mexico	55,668	23,699
Central Basin Platform	22,925	22,155
Western Delaware Basin	68,814	22,794
Williston Basin of North Dakota	42,362	11,069
Arkoma Basin of Arkansas	17,022	14,452
Total Emerging Plays	206,791	94,169
Other	39,668	28,573
Total Emerging Plays and Other	246,459	122,742

The following table sets forth the amount of our gross and net undeveloped acreage as of December 31, 2007 that will expire over the next three years by region except where production is established within applicable spacing units on such acreage prior to applicable expiration dates:

	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin:						
Southeast New Mexico	23,696	7,490	8,601	3,423	3,294	1,891

West Texas	14,155	3,200	2,726	1,975		
Emerging Plays and Other(1)	11,358	2,766	39,111	16,045	41,844	12,007
Total	49,209	13,456	50,438	21,443	45,138	13,898

(1) In the Delaware Basin Shale play in Culberson and Reeves Counties, Texas, we have the option to extend the expiration terms by two additional years on leases covering approximately 1,000 net acres whose original primary term expires between January and May 2008. Should we elect to exercise these extensions, our net cost would be approximately $80,000.

Our Oil and Natural Gas Reserves

The following table sets forth our estimated net proved oil and natural gas reserves, PV-10 and standardized measure of discounted future net cash flows as of December 31, 2007. PV-10 includes the present value of our estimated future abandonment and site restoration costs for proved properties net of the present value of estimated salvage proceeds from each of these properties. Our reserve estimates are based on independent engineering evaluations prepared by Netherland, Sewell & Associates, Inc. and Cawley Gillespie & Associates, Inc. as of December 31, 2007 ($92.50 per Bbl Plains Marketing, L.P. West Texas Intermediate posted oil price and $6.795 per MMBtu NYMEX Henry Hub spot natural gas price, adjusted for location and quality by field, were used in the computation of future net cash flows).

	Oil (MBbl)	**Gas (MMcf)**	**Total (MMcfe)**		**PV-10(1) ($MM)**
Proved developed producing	24,726	115,875	264,231	$	1,176.2
Proved developed non-producing	2,891	13,005	30,351		110.2
Proved undeveloped	25,744	96,957	251,421		852.1
Total proved	53,361	225,837	546,003	$	2,138.5
Present value of future income tax discounted at 10%					(569.1)
Standardized measure of discounted future net cash flows(2) ($MM)				$	1,431.8

(1) Non-GAAP Financial Measure and Reconciliation (unaudited) PV-10 is derived from the standardized measure of discounted future net cash flows which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of the PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

(2) Standardized measure of discounted future net cash flows is computed by applying year-end prices, costs and a discount factor of 10 % to net proved reserves, taking into account the effect of future income taxes.

The following table sets forth our estimated net proved reserves and PV-10 as of December 31, 2007, by region:

	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)	Percent of total	PV-10 ($MM)
Permian Basin:					
Southeast New Mexico	42,921	203,300	460,826	84%	$ 1,818.0
West Texas	9,877	16,013	75,275	14%	284.6
Emerging Plays and Other	563	6,524	9,902	2%	35.9
Total	53,361	225,837	546,003	100%	$ 2,138.5

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Title to Our Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our bank credit facilities, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. *Legal Proceedings*

We are not a party to any material pending legal proceedings, other than ordinary course proceedings and claims incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management does not believe that the resolution of any of these matters, and the amount of the liability, if any, ultimately incurred with respect to such proceedings and claims, will have a material adverse effect on our business, financial condition or results of operations.

Item 4. *Submission of Matters to a Vote of Shareholders*

None.

PART II

Item 5. *Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market Information

Our common stock commenced trading on the New York Stock Exchange (NYSE) under the symbol CXO on August 3, 2007 in connection with our initial public offering. The following table shows, for the periods indicated, the high and low sales prices for our common stock as reported by the NYSE.

	Price Per Share	
	High	**Low**
2007		
Third Quarter (August 3, 2007 through September 30, 2007)	$ 16.44	$ 11.60
Fourth Quarter	$ 22.30	$ 14.30

The last sale price of our common stock on March 27, 2008 was $25.37 per share, as reported by the NYSE.

As of March 27, 2008, there were 134 holders of record of our common stock.

Dividends

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. The revolving credit facility and second lien term loan facility we have with our lenders prohibit the payment of dividends on our common stock. See Item 1A. Risk Factors Risks Related to Our Common Stock and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Capital Resources and Liquidity.

Equity Compensation Plans

At December 31, 2007, a total of 5,850,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. You can find a description of our stock incentive plan under Note H *Stock incentive plan* in the notes to the consolidated financial statements.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options	(b) Weighted-Average Exercise Price of Outstanding Options	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column (a)
Equity compensation plan approved by security holders(1)	3,011,722	$ 9.71	2,406,729
Equity compensation plan not approved by security holders(2)		$	
Total	3,011,722	$ 9.71	2,406,729

(1) 2006 Stock Incentive Plan. See Note H *Stock incentive plan* in the notes to the consolidated financial statements.

(2) None.

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Item 6. *Selected Financial Data*

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes, each of which is included in this annual report.

Selected Historical Financial Information

The following table shows selected historical financial data related to Concho (as the accounting successor to Concho Equity Holdings Corp., which is now known as Concho Equity Holdings LLC) and combined financial data of the Chase Group Properties. We have accounted for the combination transaction that occurred on February 27, 2006, as an acquisition by Concho Equity Holdings Corp. of the Chase Group Properties and a simultaneous reorganization of Concho such that Concho Equity Holdings Corp. is now our wholly owned subsidiary.

Our historical results of operations for the periods presented below may not be comparable either from period to period or going forward, for the following reasons:

- Prior to December 7, 2004, Concho Equity Holdings Corp. did not own any material assets and did not conduct substantial operations other than organizational activities.

- On December 7, 2004, Concho Equity Holdings Corp. acquired the Lowe Properties for approximately $117 million and commenced oil and gas operations.

- On February 27, 2006, the initial closing of the combination transaction occurred, and Concho acquired the Chase Group Properties for approximately 35 million shares of common stock and approximately $409 million in cash.

- On March 27, 2007, Concho entered into a $200.0 million second lien term loan facility from which it received proceeds of $199.0 million that it used to repay the $39.8 million outstanding under its prior term loan facility and to reduce the outstanding balance under its revolving credit facility by $154.0 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes.

- In August 2007, Concho completed its initial public offering of common stock from which it received proceeds of approximately $173.0 million that it used to retire outstanding borrowings under its second lien term loan facility totaling $86.5 million and to retire outstanding borrowings under its revolving credit facility totaling $86.5 million.

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The historical financial data for the Chase Group Properties for the years ended December 31, 2005, 2004 and 2003 are derived from the audited financial statements of the Chase Group Properties included in our prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424(b) on August 3, 2007. The historical financial data for Concho for the years ended December 31, 2007, 2006 and 2005, and for the period from inception (April 21, 2004) through December 31, 2004, are derived from the audited financial statements of Concho.

	Concho Resources Inc.				Chase Group Properties		
	Years Ended December 31,			Inception (April 21, 2004) through December 31,			
	2007	2006 (1)	2005	2004 (2)	2005	2004	2003
	(In thousands, except per share amounts)						
Statement of operations data:							
Operating revenues:							
Oil sales	$ 195,596	$ 131,773	$ 31,621	$ 1,851	$ 73,132	$ 66,529	$ 62,016
Natural gas sales	98,737	66,517	23,315	1,771	46,546	41,247	41,486
Total operating revenues	294,333	198,290	54,936	3,622	119,678	107,776	103,502
Operating costs and expenses:							
Oil and gas production	29,966	22,060	10,923	512	12,979	11,762	9,868
Oil and gas production taxes	24,301	15,762	3,712	234	10,298	9,202	8,815
Exploration and abandonments	29,098	5,612	2,666	1,850		179	2,116
Depreciation, depletion and accretion	77,223	61,009	11,574	963	19,092	20,459	19,643
Impairments of proved oil and gas properties	7,267	9,891	2,295		194	3,233	2,065
Contract drilling fees stacked rigs	4,269						
General and administrative	21,336	12,577	8,055	3,086	1,702	1,387	1,246
Stock-based compensation	3,841	9,144	3,252	1,128			
Ineffective portion of cash flow hedges	821	(1,193)	1,148				
(Gain) loss on derivatives not designated as hedges	20,274		5,001	(684)	1,062	7,936	576
Total operating costs and expenses	218,396	134,862	48,626	7,089	45,327	54,158	44,329
	75,937	63,428	6,310	(3,467)	74,351	53,618	59,173

Income (loss) from operations										
Other income (expense):										
Interest expense	(36,042)	(30,567)	(3,096)	(272)						
Other, net	1,484	1,186	779	168						
Total other expense	(34,558)	(29,381)	(2,317)	(104)						
Income (loss) before income taxes	41,379	34,047	3,993	(3,571)		74,351		53,618		59,173
Income tax (expense) benefit	(16,019)	(14,379)	(2,039)	915						
Net income (loss)	25,360	19,668	1,954	(2,656)	$	74,351	$	53,618	$	59,173
Preferred stock dividends	(45)	(1,244)	(4,766)	(804)						
Effect of induced conversion of preferred stock		11,601								

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	Concho Resources Inc.				Chase Group Properties		
	Years Ended December 31,			Inception (April 21, 2004) through December 31,			
	2007	2006 (1)	2005	2004 (2)	2005	2004	2003
	(In thousands, except per share amounts)						
Net income (loss) applicable to common shareholders	$ 25,315	$ 30,025	$ (2,812)	$ (3,460)			
Basic earnings (loss) per share:							
Net income (loss) per share	$ 0.39	$ 0.63	$ (0.70)	$ (3.48)			
Weighted average shares used in basic earnings (loss) per share	64,316	47,287	4,059	994			
Diluted earnings (loss) per share:							
Net income (loss) per share	$ 0.38	$ 0.59	$ (0.70)	$ (3.48)			
Weighted average shares used in diluted earnings (loss) per share	66,309	50,729	4,059	994			

	Concho Resources Inc.				Chase Group Properties		
	Years Ended December 31,			Inception (April 21, 2004) through December 31,	Years Ended December 31,		
	2007	2006(1)	2005	2004(2)	2005	2004	2003
	(In thousands)						
Other financial data:							
Net cash provided by (used in) operations	$ 169,769	$ 112,181	$ 25,070	$ (2,193)	$ 93,162	$ 84,202	$ 84,264
Net cash provided by (used in) investing	(160,353)	(596,852)	(61,902)	(122,473)	(35,611)	(30,045)	(31,823)
Net cash provided by (used in) financing	19,886	476,611	45,358	125,322	(57,551)	(54,157)	(52,441)
Capital expenditures	190,634	1,226,180	72,758	116,880	32,352	25,451	29,449

Concho Resources Inc.

	As of December 31,				Chase Group Properties As of December 31,	
	2007	2006(1)	2005	2004(2)	2005	2004
	(In thousands)					
Balance sheet data:						
Cash and cash equivalents	$ 30,424	$ 1,122	$ 9,182	$ 656	$	$
Property and equipment, net	1,394,994	1,320,655	170,583	115,455	149,042	135,568
Total assets	1,508,229	1,390,072	232,385	130,717	161,792	145,100
Long-term debt, including current maturities	327,404	495,500	72,000	53,000		
Stockholders equity / net investment	775,398	575,156	109,670	71,710	150,814	134,014

(1) The acquisition of the Chase Group Properties was substantially consummated on February 27, 2006. See Note D *Business Combination* in the consolidated financial statements.

(2) The acquisition of the Lowe Properties was completed on December 7, 2004. See Selected Historical Financial and Operating Information for Lowe Properties below.

Selected Historical Financial and Operating Information for Lowe Properties

The selected financial data for the Lowe Properties for the year ended December 31, 2003 and for the period from January 1, 2004 through November 30, 2004 were derived from the audited statements of revenue and direct

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operating expenses of the Lowe Properties included in our prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424(b) on August 3, 2007 and information provided by the seller.

	Year Ended December 31, 2003	Period from January 1, through November 30, 2004
	(In thousands)	
Revenues	$ 32,371	$ 34,663
Direct operating expenses:		
Lease operating expense	6,652	6,983
Production tax expense	2,023	2,159
Other expenses	435	461
Total operating costs and expenses	9,110	9,603
Revenues in excess of direct operating expenses	$ 23,261	$ 25,060

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this annual report.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenue and expenses to differ materially from our expectations.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of producing oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We have also acquired significant acreage positions in unconventional emerging resource plays located in the Permian Basin of Southeast New Mexico, the Central Basin Platform and the Western Delaware Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. Crude oil comprised 59% of our 546.0 Bcfe of estimated net proved reserves as of December 31, 2007, and 60% of our 30.1 Bcfe of production for the year ended December 31, 2007. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 90% of our PV-10 and 50% of our 2,067 wells as of December 31, 2007. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Factors that Significantly Affect Our Results

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas that we can economically produce and our ability to access capital.

We use commodity derivative contracts covering a portion of our expected future oil and natural gas production to reduce our exposure to fluctuations in commodity price. See Liquidity and Capital Resources Commodity Derivatives and Hedging for a discussion of our commodity derivatives, hedging and hedge positions.

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Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce and by implementing secondary recovery techniques. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on costs necessary to produce our reserves as well as the costs necessary to add reserves through drilling and acquisitions. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost-effective manner and to timely obtain drilling permits and regulatory approvals.

Items Impacting Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either from period to period or going forward, for the reasons described below.

Combination Transaction

On February 24, 2006, we entered into a combination agreement in which we agreed to purchase certain oil and gas properties owned by the Chase Group and combine them with substantially all of the outstanding equity interests of Concho Equity Holdings Corp. to form our company. The initial closing of the transactions contemplated by the combination agreement occurred on February 27, 2006. As a result of the initial closing of the combination transaction, the members of the Chase Group that sold their working interests to us at the initial closing of the combination transaction received 34,683,315 shares of our common stock and approximately $400 million in cash, and the former shareholders of Concho Equity Holdings Corp. that were a party to the combination agreement received 23,767,691 shares of our common stock. In addition, certain options held by our employees to purchase preferred and common stock of Concho Equity Holdings Corp. were converted into options to purchase 2,349,113 shares of our common stock. The executive officers of Concho Equity Holdings Corp. became the executive officers of our company in connection with the initial closing of the combination transaction. We have accounted for the combination transaction as a reorganization of our company, such that Concho Equity Holdings Corp. is now our wholly owned subsidiary, and a simultaneous acquisition by our company of the assets contributed by the Chase Group.

We agreed in the combination agreement to offer to acquire additional interests in the Chase Group Properties from persons associated with the Chase Group. In May 2006, we acquired certain of such interests from ten of such persons in exchange for an aggregate consideration of 111,323 shares of our common stock and $8.9 million in cash. In April 2007, we acquired the remainder of such interests from an additional nine persons for 54,230 shares of our common stock and $256,000 in cash. Terms concerning the exchange of such interests for shares of our common stock were the same as the terms in the combination agreement.

In addition, because certain employee stockholders of Concho Equity Holdings Corp. were not confirmed to have been accredited investors at the time of the combination transaction, their 254,621 units, consisting of one preferred and one-half of a common share of Concho Equity Holdings Corp., could not be immediately exchanged for our common shares. On April 16, 2007, these remaining shares of Concho Equity Holdings Corp. were exchanged for 318,285 shares of our common stock. As a result, Concho Equity Holdings Corp. is now our wholly owned subsidiary. The common and preferred shares of Concho Equity Holdings Corp., which were outstanding between February 27, 2006 and April 16, 2007, have been treated as exchangeable for and equivalent to shares of our common stock in our consolidated financial statements.

We completed the initial public offering of our common stock in August 2007, and a secondary public offering of our common stock by certain of our shareholders in December 2007.

Concho Equity Holdings Corp. is our predecessor for accounting purposes. As a result, our historical financial statements prior to February 27, 2006, are the financial statements of Concho Equity Holdings Corp. Concho Equity Holdings Corp. was formed on April 21, 2004, and did not own any material assets and did not conduct substantial

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operations other than organizational activities until it acquired the Lowe Properties on December 7, 2004. For a discussion of the results of operations of Concho (as the accounting successor to Concho Equity Holdings Corp.), See Results of Operations. The financial statements of Concho (as the accounting successor to Concho Equity Holdings Corp.), together with the notes thereto, are also included in this annual report.

Additional Indebtedness and Other Expenses

During 2007 and 2006, we incurred additional indebtedness and other expenses as a result of our rapid growth, particularly as a result of the combination transaction. Our historical financial information prior to 2006 does not give effect to various items that will affect our results of operations and liquidity in the future, including the following items:

- we closed the combination transaction on February 27, 2006 and properties were contributed to us by the Chase Group that represented approximately 76% of our PV-10 as of December 31, 2006 and approximately 81% of our PV-10 as of December 31, 2007;

- we incurred approximately $405 million of new indebtedness upon the initial closing of the combination transaction, which was borrowed on our revolving credit facility dated February 24, 2006 (1st Lien Credit Facility);

- we entered into a $200.0 million second lien term loan facility on March 27, 2007 (New 2nd Lien Credit Facility), from which we received proceeds of $199.0 million that we used to repay the $39.8 million outstanding under our prior term loan facility dated July 6, 2006 (2nd Lien Credit Facility), to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes;

- we received proceeds of $173.0 million from our initial public offering in August 2007, all of which we used to reduce outstanding borrowings under our debt facilities; and

- we have incurred additional general and administrative costs as a result of the expansion of our technical and administrative staffs and as a result of increased amounts of professional fees.

Curtailment of Drilling

We determined in January 2007 to reduce our drilling activities for the three months ended March 31, 2007. This determination was due to a decline in oil and natural gas prices in January 2007 compared to such prices in the fourth quarter of 2006, the costs of goods and services necessary to complete our drilling activities and the resulting effect of these circumstances on our expected cash flow. To preserve our liquidity, we reduced our drilling activities and curtailed capital expenditures until we were able to complete our second lien term loan facility in March 2007. Also due to the reduced drilling activities described above, we recorded an expense during the six months ended June 30, 2007 of $4.3 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts. Approximately $3 million of this amount was paid to Silver Oak Drilling, LLC, which is an affiliate of the Chase Group. We resumed drilling activities in April 2007, and we invested our entire 2007 exploration and development budget of approximately $183 million prior to January 1, 2008. We incurred no contract drilling fees related to stacked rigs in the six months ended December 31, 2007.

Natural Gas Processing Plant Interruption

On June 27, 2007, we were notified that a natural gas processing plant through which we process and sell a portion of the production from our Shelf Properties in New Mexico was shut-down for repairs as a result of a storm. Approximately 40 MMcfe per day of our production was shut-in as a result of this plant shut-down. The plant became fully operational on July 3, 2007, and we resumed production from all of our properties that had been affected. On July 16, 2007, this plant was shut-down again for repairs. Approximately 40 MMcfe per day of our production was shut-in again as a result of this plant shut-down. The plant became fully operational on July 20, 2007, and we resumed production from all of our properties that had been affected. As a result of this plant downtime and associated gathering system interruptions and high line pressure, our production delivery was further restricted in varying amounts during late July and the full months of August and September. Our total net production during the year ended December 31, 2007 was reduced by approximately 660 MMcfe as a result of this situation. These production delivery restrictions were reduced significantly toward the end of September and the beginning of October and, as a result, we resumed full levels of production delivery during the month of October.

Initial Public Offering

On August 7, 2007, we completed an initial public offering (the IPO) of our common stock. We sold 13,332,851 shares and certain shareholders, including our executive officers and members of the Chase Group, sold 7,554,256 shares of our common stock, in each case, at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.5 million, we received net proceeds of approximately $139.2 million. In conjunction with the IPO, the underwriters were granted an option to purchase from us 3,133,066 additional shares of our common stock. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.2 million, we received net proceeds of approximately $33.8 million. The aggregate net proceeds of approximately $173.0 million received by us at closings on August 7, 2007 and August 9, 2007 were utilized in equal parts to repay a portion of our New 2nd Lien Credit Facility on August 9, 2007, and to prepay a portion of our 1st Lien Credit Facility on August 20, 2007. Approximately $1 million of the deferred loan costs associated with our New 2nd Lien Credit Facility were written off to interest expense in August 2007. Additionally, approximately $0.4 million of the unamortized original issue discount related to our 2nd Lien Credit Facility was written off to interest expense in August 2007.

Secondary Public Offering

On December 19, 2007, we completed a secondary public offering of 11,845,000 shares of our common stock sold by certain of our stockholders, including certain members of the Chase Group, pursuant to a registration statement that we previously filed with SEC. Certain members of the Chase Group sold 10,194,732 shares in the aggregate and certain other stockholders sold 1,650,268 shares in the aggregate, including one of our executive officers who sold 45,000 shares. Chase Oil granted the underwriters an option to purchase up to 1,776,615 additional shares to cover over-allotments. The underwriters fully exercised this option and purchased the additional shares on December 19, 2007. We did not receive any proceeds from the sale of the shares sold in this secondary offering.

Public Company Expenses

In addition, we believe that our expected future financial results will be impacted as a result of our having become a public corporation in August 2007. We anticipate incurring additional general and administrative expenses relating to operating as a separate publicly held corporation, including costs associated with annual and quarterly reports to stockholders, costs associated with our compliance with the Sarbanes-Oxley Act of 2002, independent auditor fees, investor relations activities, registrar and transfer agent fees, legal fees, incremental director and officer liability insurance costs, and director compensation.

Amendment of Certain Outstanding Stock Options

On November 8, 2007, the compensation committee of our board of directors authorized amendments to certain outstanding agreements related to options to purchase our common stock that were previously awarded to certain of our executive officers and employees in order to amend such award agreements so that the subject stock option awards would constitute deferred compensation that is compliant with Section 409A of the Internal Revenue Code of 1986, as amended, or exempt such awards from the application of Section 409A. Because the offer to amend outstanding stock option agreements previously issued to our employees may constitute a tender offer under the Exchange Act, on November 8, 2007, our board of directors authorized commencement of a tender offer to amend the applicable outstanding stock option award agreements in the form approved by the compensation committee. All affected employees accepted the tender offer.

Generally, the amendments provide that the employee stock options, which had previously vested in connection with the combination transaction, will become exercisable in 25% increments over a four year period or upon the occurrence of certain specified events. Each employee who elected to amend his stock option award agreement received on January 2, 2008 a cash payment equal to $0.50 for each share of common stock subject to the amendment, totaling approximately $192,000 for all such employees. Our affected executive officers accepted our offer to amend certain of their stock option awards issued prior to the combination transaction on substantially the same terms, except such executive officers were not offered the $0.50 per share cash payment. Each of these executive officers executed respective amendments on November 16, 2007, prior to the initiation of the tender offer to our non-executive employees.

In addition, our executive officers at the time received stock option awards in June 2006 to purchase 450,000 shares of common stock, in the aggregate, at a purchase price of $12.00 per share. We subsequently determined that the fair market value of a share of common stock as of the date of the award was $15.40. As a result, the compensation committee of our board of directors authorized and approved an amendment to these stock option award agreements pursuant to which the exercise price of such stock options would be increased from $12.00 per share to $15.40 per share. This represents incremental value of approximately $0.8 million above the value of the June 2006 options. Such incremental value will be recognized in *General and administrative expense* in our consolidated statement of operations beginning in November 2007 continuing through the remaining vesting period. Such executive officers executed these amendments on November 16, 2007. To compensate such executive officers for the $3.40 increase in the exercise price, we issued to each of them an award of the number of shares of restricted stock equal to (i) the product of $3.40 and the number of shares of common stock subject to the stock option award, divided by (ii) $18.38, which was the mean of the high and low sales price of a share of our common stock on November 19, 2007. As a result, such executive officers were granted 83,242 shares of restricted stock in the aggregate on November 19, 2007 based on a grant price of $18.38. The lapse of forfeiture restrictions on this restricted stock is in 25% increments, respectively, on January 1, 2008, June 12, 2008, June 12, 2009, and June 12, 2010, or upon the occurrence of certain specified events.

We have determined that our aggregate compensation expense of approximately $0.8 million resulting from these proposed modifications will be recorded during the period from November 8 to December 31, 2007, and during the years ending December 31, 2008, 2009, and 2010.

Results of Operations

The following table presents selected financial and operating information of Concho (as successor to Concho Equity Holdings Corp.) for the years ended December 31, 2007, 2006 and 2005:

	December 31,		
	2007	2006	2005
	(In thousands, except price data)		
Oil sales	$ 195,596	$ 131,773	$ 31,621
Natural gas sales	98,737	66,517	23,315
Total operating revenues	294,333	198,290	54,936
Operating costs and expenses	218,396	134,862	48,626
Interest, net and other revenue	34,558	29,381	2,317
Income before income taxes	41,379	34,047	3,993
Income tax expense	(16,019)	(14,379)	(2,039)
Net income	$ 25,360	$ 19,668	$ 1,954
Production volumes:			
Oil (MBbl)	3,014	2,295	599
Natural gas (MMcf)	12,064	9,507	3,404
Natural gas equivalent (MMcfe)	30,148	23,275	6,998
Average prices:			
Oil, without hedges ($/Bbl)	$ 68.58	$ 60.47	$ 54.71
Oil, with hedges ($/Bbl)	$ 64.90	$ 57.42	$ 52.79
Natural gas, without hedges ($/Mcf)	$ 8.08	$ 6.87	$ 6.99
Natural gas, with hedges ($/Mcf)	$ 8.18	$ 7.00	$ 6.85
Natural gas equivalent, without hedges ($/Mcfe)	$ 10.09	$ 8.77	$ 8.08
Natural gas equivalent, with hedges ($/Mcfe)	$ 9.76	$ 8.52	$ 7.85

Year ended December 31, 2007, compared to year ended December 31, 2006

Oil and gas revenues. Revenue from oil and gas operations was $294.33 million for the year ended December 31, 2007, an increase of $96.04 million (48%) from $198.29 million for the year ended December 31, 2006. This increase was primarily because of increased production as a result of the acquisition of the Chase Group Properties and secondarily due to successful drilling efforts during 2006 and 2007, coupled with moderate increases in realized oil and gas prices. In addition:

average realized oil prices (after giving effect to hedging activities) were $64.90 per Bbl during the year ended December 31, 2007, an increase of 13% from $57.42 per Bbl during the year ended December 31, 2006;

total oil production was 3,014 MBbl for the year ended December 31, 2007, an increase of 719 MBbl (31%) from 2,295MBbl for the year ended December 31, 2006;

average realized natural gas prices (after giving effect to hedging activities) were $8.18 per Mcf during the year ended December 31, 2007, an increase of 17% from $7.00 per Mcf during the year ended December 31, 2006;

total natural gas production was 12,064 MMcf for the year ended December 31, 2007, an increase of 2,557 MMcf (27%) from 9,507 MMcf for the year ended December 31, 2006;

average realized natural gas equivalent prices (after giving effect to hedging activities) were $9.76 per Mcfe during the year ended December 31, 2007, an increase of 15% from $8.52 per Mcfe during the year ended December 31, 2006;

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total production was 30,148 MMcfe for the year ended December 31, 2007, an increase of 6,873 MMcfe (30%) from 23,275 MMcfe for the year ended December 31, 2006; and

total production during the year ended December 31, 2007 was reduced by approximately 660 MMcfe as a result of the temporary shut-downs of a natural gas processing plant through which we process and sell a portion of our production. See Items Impacting Comparability of our Financial Results Natural Gas Processing Plant Interruption.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. Following is a summary of the effects of commodity hedges for the year ended December 31, 2007 and 2006:

	Crude Oil Hedges Year Ended December 31,		**Natural Gas Hedges Year Ended December 31,**	
	2007	**2006**	**2007**	**2006**
Hedging revenue increase (decrease)	$ (11,091,000)	$ (7,000,000)	$ 1,291,000	$ 1,232,000
Hedged volumes (Bbls and MMBtus, respectively)	1,076,750	1,080,500	6,482,600	5,447,500
Hedged revenue increase (decrease) per hedged volume	$ (10.30)	$ (6.48)	$ 0.20	$ 0.23

During the year ended December 31, 2007, our commodity price hedges decreased oil revenues by $11.09 million ($3.68 per Bbl). During the year ended December 31, 2006, our commodity price hedges decreased oil revenues by $7.00 million ($3.05 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the year ended December 31, 2007 more than their effect of decreasing oil revenues during the year ended December 31, 2006 was the result of (1) a higher average market price of NYMEX crude oil of $72.39 per Bbl in 2007 as compared to $66.21 per Bbl in 2006, and (2) the higher hedged revenue per hedged volume in 2007 as compared to 2006, as shown in the table above, partially offset by a lower amount of hedged volumes of 1,076,750 Bbls in 2007 as compared to 1,080,500 Bbls in 2006.

During the year ended December 31, 2007, our commodity price hedges increased gas revenues by $1.29 million ($0.11 per Mcf). During the year ended December 31, 2006, our commodity price hedges increased gas revenues by $1.23 million ($0.13 per Mcf). The effect of commodity price hedges in increasing gas revenues in 2007 more than their effect of increasing gas revenues in 2006 was the result of a higher amount of hedged volumes of 6,482,600 MMBtus in 2007 as compared to 5,447,500 MMBtus in 2006, partially offset by (1) the lower hedged revenue per hedged volume in 2007 as compared to 2006 and (2) a higher reference market price for natural gas of $6.11 per MMBtu in 2007 as compared to $6.05 per MMBtu in 2006, as shown in the table above.

As of June 30, 2007, we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 133. As a result, any amounts in *Accumulated other comprehensive income (AOCI) AOCI* as of June 30, 2007 related to these dedesignated hedges will remain in *AOCI* and be reclassified into earnings under *Natural gas revenues* during the periods which the hedged forecasted transaction affects earnings. Cash settlements for these natural gas contracts will be recorded to *(Gain) loss on derivatives not designated as hedges*. Regarding the dedesignated contracts, for the period January 1, 2007 through June 30, 2007, when these natural gas contracts qualified to use hedge accounting, the cash settlement receipts of approximately $0.19 million were recorded in *Natural gas revenues*. For the period July 1, 2007 through December 31, 2007, when these natural gas contracts no longer qualified to use hedge accounting, a pre-tax amount of $1.10 million was reclassified from *AOCI* to *Natural gas revenues* and cash settlement receipts of $1.82 million was recorded to *(Gain) loss on derivatives not designated as hedges*. See Note I *Derivative financial instruments* in the notes to the consolidated financial statements.

Production expenses. Production expenses (including production taxes) were $54.27 million ($1.80 per Mcfe) for the year ended December 31, 2007, an increase of $16.45 million (43%) from $37.82 million ($1.62 per Mcfe) for the year ended December 31, 2006. The increase in production expenses is due to: (1) production expenses associated with the Chase Group Properties acquired in February 2006 of approximately $2.15 million, (2) production expenses associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities, (3) an increase in repair activity on a well in Gaines County, Texas in the amount of $1.44 million, and (4) an increase in production taxes as discussed below. Lease operating expenses and workover costs comprised approximately 55% and 58% of production expenses for the year ended December 31, 2007 and 2006, respectively. These costs per unit of production were $0.99 per Mcfe during the year ended December 31, 2007, an increase of 5% from $0.95 per Mcfe during the year ended December 31, 2006. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 7% and 5% of lease operating expenses for the year ended December 31, 2007 and 2006, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 45% and 42% of production expenses during the year ended December 31, 2007 and 2006, respectively. Production taxes per unit of production were $0.81 per Mcfe during the year ended December 31, 2007, an increase of 19% from $0.68 per Mcfe during the year ended December 31, 2006. This increase was primarily due to an increase in average natural gas equivalent prices we received.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the year ended December 31, 2007 and 2006:

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(In thousands)	
Geological and geophysical	$ 4,089	$ 2,185
Exploratory dry holes	21,923	3,192
Leasehold abandonments	3,086	235
Total exploration and abandonments	$ 29,098	$ 5,612

Our geological and geophysical expense, which primarily consists of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis, during the year ended December 31, 2007 was $4.09 million, an increase of $1.90 million from $2.19 million for the year ended December 31, 2006. This 87% increase is primarily attributable to a comprehensive seismic survey on our Shelf Properties which was initiated in December 2007.

Our exploratory dry holes expense during the year ended December 31, 2007 is primarily attributable to five operated exploratory wells that were unsuccessful. The costs associated with three of these wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $17.04 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.36 million. An additional $0.81 million was charged to exploratory dry hole costs relative to a target zone in the fifth of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which was determined to be dry. Exploration expense of $1.68 million related to three outside operated wells located in Eddy County, New Mexico was also recorded.

Of our exploratory dry holes expense during the year ended December 31, 2006, $3.19 million was attributable to one exploratory dry hole in Gaines County, Texas that we operated and one exploratory dry hole in Val Verde County, Texas operated by another company.

For the year ended December 31, 2007, we recorded $3.09 million of leasehold abandonments, of which $0.69 million related to a prospect in Lea County, New Mexico, $0.77 million related to one prospect located in Edwards County, Texas and $0.54 million related to leasehold expiring in Southeast New Mexico. The remaining $1.09 million was related to several individually minor leaseholds. We had minimal leasehold abandonments during the year ended December 31, 2006.

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Depreciation and depletion expense. Depreciation and depletion expense was $76.78 million ($2.55 per Mcfe) for the year ended December 31, 2007, an increase of $16.06 million from $60.72 million ($2.61 per Mcfe) for the year ended December 31, 2006. The increase in depreciation and depletion expense was primarily due to the acquisition of the Chase Group Properties and related acquisition costs associated with the combination transaction as well as the costs capitalized associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities. The decrease in depreciation and depletion expense per Mcfe was primarily due to an increase in proved oil and natural gas reserves as a result of our successful development and exploratory drilling program.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during the year ended December 31, 2007, we recognized a non-cash charge against earnings of $7.27 million, 33% of which related to wells drilled in Gaines County, Texas, 30% of which related to a well drilled in Schleicher County, Texas and 18% of which related to a well drilled in Crane County, Texas. The remaining 19% was comprised of multiple immaterial wells in various counties. For the year ended December 31, 2006, we recognized a non-cash charge against earnings of $9.89 million, 33% of which related to wells located in Pecos and Midland Counties, Texas, acquired in our Lowe Acquisition, 24% of which related to wells located in Lea and Eddy Counties, New Mexico, acquired in our Lowe Acquisition, 11% of which related to a well drilled in Eddy County, New Mexico and 9% of which related to a well drilled in Mountrail County, North Dakota. The remaining 23% was comprised of multiple immaterial wells in various counties.

Contract drilling fees stacked rigs. As discussed above under Items impacting comparability of our financial results Curtailment of drilling, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the six months ended June 30, 2007 of approximately $4.27 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. No additional costs were incurred from July 1, 2007 through December 31, 2007. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. These costs were minimized during the first six months of 2007 as one contractor secured work for a rig for 71 days during that period and charged us only the difference between the then-current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

General and administrative expenses. General and administrative expenses were $25.18 million ($0.84 per Mcfe) for the year ended December 31, 2007, an increase of $3.46 million (16%) from $21.72 million ($0.93 per Mcfe) for the year ended December 31, 2006. Non-cash stock-based compensation was $3.84 million during the year ended December 31, 2007 and $9.14 million during the year ended December 31, 2006. General and administrative expenses, excluding non-cash stock-based compensation, (Net general expense) were $21.34 million ($0.71 per Mcfe) for the year ended December 31, 2007, an increase of $8.76 million (70%) from $12.58 million ($0.54 per Mcfe) for the year ended December 31, 2006. The increase in Net general expenses during the year ended December 31, 2007 was primarily due to an increase in the number of employees and related personnel expenses. Annual bonuses in the aggregate amount of $2.53 million were paid to the officers and employees in April 2007 representing bonuses for 2006 performance as compared to $0.91 million aggregate bonuses paid to employees in February 2006. Additionally, as of December 31, 2007, we accrued officer and employee bonuses of $3.40 million related to 2007 performance. All of these bonuses were approved by the compensation committee of our board of directors.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $1.08 million and $0.80 million during the year ended December 31, 2007 and 2006, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

(Gain) loss on derivatives not designated as cash flow hedges. As explained in *Hedging activities*, during the three months ended September 30, 2007, we determined that all of our natural gas commodity contracts no longer qualified

as hedges under the requirements of SFAS No. 133. If the hedge is no longer highly effective, according to SFAS No. 133, an entity shall discontinue hedge accounting for an existing hedge, prospectively and during the period the hedges became ineffective. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges* and any related cash settlements are recorded to *(Gain) loss on derivatives not designated as hedges*. For the six months since de-designation beginning on July 1, 2007, the related cash settlement receipts was approximately $1.82 million. The non-cash mark-to-market adjustment for other derivative instruments not designated as cash flow hedges was a loss of $22.09 million.

Interest expense. Interest expense was $36.04 million for the year ended December 31, 2007, an increase of $5.48 million from $30.57 million for the year ended December 31, 2006. The weighted average interest rate for the year ended December 31, 2007 and 2006 was 7.7% and 7.5%, respectively. The weighted average debt balance during the year ended December 31, 2007 and 2006 was approximately $436.30 million and $406.78 million, respectively. The increase in weighted average debt balance during the year ended December 31, 2007 was due to our borrowings to fund our drilling activities, partially offset by the partial prepayment in August 2007 of $86.60 million on the New 2nd Lien Credit Facility and the repayment in August 2007 of $86.60 million on the 1st Lien Credit Facility. The increase in interest expense is due to a slight increase in the weighted average interest rate, the increase in the weighted average debt and the acceleration of deferred loan cost amortization and original issue discount amortization. In March 2007, we reduced the 1st Lien Credit Facility borrowing base by $100.00 million, or 21%, resulting in accelerated amortization of $0.77 million, and the full repayment of the 2nd Lien Credit Facility resulting in accelerated amortization of $0.43 million. The prepayment of $86.60 million on the New 2nd Lien Credit Facility in August 2007 resulted in accelerated amortization of $1.02 million in deferred loan costs and $0.41 million in original issue discount.

Income tax provisions. We recorded income tax expense of $16.02 million and $14.38 million for the year ended December 31, 2007 and 2006, respectively. The effective income tax rate for the years ended December 31, 2007 and 2006 was 38.7% and 42.2%, respectively.

We had a net deferred tax liability of $245.57 million and $241.67 million at December 31, 2007 and December 31, 2006, respectively. The net liability balance is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006. The net change is due to 2007 intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principles in the United States of America, partially offset by an increase in deferred hedge losses.

Year ended December 31, 2006, compared to year ended December 31, 2005

Oil and gas revenues. Revenue from oil and gas operations was $198.29 million for the year ended December 31, 2006, an increase of $143.35 million (261%) from $54.94 million for the year ended December 31, 2005. This increase was primarily because of increased production as a result of the acquisition of the Chase Group Properties and secondarily due to successful drilling efforts during 2005 and 2006. The increases in revenue and production attributable to the Chase Group Properties between 2005 and 2006 were $136.23 million and 11,747 MMcfe, respectively. In addition:

- average realized oil prices (after giving effect to hedging activities) were $57.42 per Bbl in 2006, an increase of 9% from $52.79 per Bbl in 2005;

- total oil production was 2,295 MBbl for the year ended December 31, 2006, an increase of 1,696 MBbl (283%) from 599 MBbl for the year ended December 31, 2005;

- average realized natural gas prices (after giving effect to hedging activities) were $7.00 per Mcf in 2006, an increase of 2% from $6.85 per Mcf in 2005;

total natural gas production was 9,507 MMcf for the year ended December 31, 2006, an increase of 6,103 MMcf (179%) from 3,404 MMcf for the year ended December 31, 2005;

average realized natural gas equivalent prices (after giving effect to hedging activities) were $8.52 per Mcfe in 2006, an increase of 9% from $7.85 per Mcfe in 2005; and

total production was 23,275 MMcfe for the year ended December 31, 2006, an increase of 16,277 MMcfe (233%) from 6,998 MMcfe for the year ended December 31, 2005.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. During 2006, our commodity price hedges decreased oil revenues by $7.00 million ($3.05 per Bbl) and increased gas revenues by $1.23 million ($0.13 per Mcf). During 2005, our commodity price hedges decreased oil revenues by $1.15 million ($1.92 per Bbl) and decreased gas revenues by $0.47 million ($0.14 per Mcf).

	Crude Oil Hedges Year Ended December 31,		Natural Gas Hedges Year Ended December 31,	
	2006	2005	2006	2005
Hedging revenue increase (decrease)	$ (7,000,000)	$ (1,150,000)	$ 1,232,000	$ (472,000)
Hedged volumes (Bbls and MMBtus, respectively)	1,080,500	109,500	5,447,500	547,500
Hedged revenue increase (decrease) per hedged volume	$ (6.48)	$ (10.50)	$ 0.23	$ (0.86)

The increased effect of the commodity price hedges in reducing oil revenues during 2006 as compared to 2005 was the result of (1) increased hedged volumes to 1,080,500 Bbls in 2006 from 109,500 Bbls in 2005 and (2) an increase in the market price of NYMEX crude oil to an average of $66.21 per Bbl in 2006 from an average of $56.57 per Bbl in 2005. The effect of the commodity price hedges in increasing gas revenues during 2006 as compared to reducing gas revenues in 2005 was the result of (1) increased hedged volumes to 5,447,500 MMBtus in 2006 from 547,500 MMBtus in 2005 and (2) a decrease in the reference market price of natural gas to $6.05 per MMBtu in 2006 from an average of $7.17 per MMBtu in 2005.

Production expenses Production expenses (including production taxes) were $37.82 million ($1.62 per Mcfe) for the year ended December 31, 2006, an increase of $23.18 million (158%) from $14.64 million ($2.09 per Mcfe) for the year ended December 31, 2005. The increase in production expenses is due to two sources: (1) production costs associated with the Chase Group Properties acquired in February 2006 of approximately $20.25 million and (2) costs associated with new wells that were successfully completed in 2006 and 2005 as a result of our drilling activities. Lease operating expenses and workover costs comprised approximately 58% and 75% of production expenses for 2006 and 2005, respectively. These costs per unit of production were $0.95 per Mcfe in 2006, a decrease of 39% from $1.56 per Mcfe in 2005. This is because the Chase Group Properties are, on average, less expensive to operate than the properties we operated prior to the combination transaction. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 5% and 9% of lease operating expenses for 2006 and 2005, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 42% and 25% of production expenses for 2006 and 2005, respectively. Production taxes per unit of production were $0.68 per Mcfe in 2006, an increase of 28% from $0.53 per Mcfe in 2005. This increase was primarily due to an increase in commodity prices.

Exploration and abandonment expense. The following table provides a breakdown of our exploration and abandonments expense for the year ended December 31, 2006 and 2005:

	Year Ended December 31, 2006	Year Ended December 31, 2005
	(In thousands)	
Geological and geophysical	$ 2,185	$ 1,113
Exploratory dry holes	3,192	1,355
Leasehold abandonments and other	235	198
Total exploration and abandonments	$ 5,612	$ 2,666

Exploration and abandonments expense were $5.61 million during 2006, an increase of $2.94 million from $2.67 million during 2005. The exploration and abandonments expense during 2006 consisted of $3.42 million of exploratory dry hole costs and leasehold abandonments and $2.19 million of geological and geophysical costs. The exploratory dry hole costs during 2006 were attributable to one exploratory dry hole in Gaines County, Texas that we operated and one exploratory dry hole in Val Verde County, Texas operated by another company. The geological and geophysical costs for 2006 primarily consisted of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis. The exploration and abandonments expense during 2005 consisted of $1.56 million of exploratory dry hole costs and leasehold abandonments and $1.11 million of geological and geophysical costs. The exploratory dry hole costs during 2005 were attributable to one exploratory dry hole in each of Eddy and Lea Counties, New Mexico that we operated and to one exploratory dry hole in Zapata County, Texas operated by another company. The geological and geophysical costs for 2005 primarily consisted of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis.

Depreciation and depletion expense. Total depreciation and depletion expense was $60.72 million ($2.61 per Mcfe) for the year ended December 31, 2006, an increase of $49.23 million (428%) from $11.49 million ($1.64 per Mcfe) for the year ended December 31, 2005. The increase in total expense and expense per Mcfe was primarily due to the acquisition of the Chase Group Properties and related acquisition costs associated with the combination transaction. Approximately $30.7 million of the increase in depreciation and depletion expense for 2006 was attributable to the acquisition of the Chase Group Properties.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during 2006, we recognized a non-cash charge against earnings of $9.89 million related to our proved oil and gas properties. Of this amount, $0.1 million was related to the Chase Group Properties. For the year ended December 31, 2005, we recognized a non-cash charge against earnings of $2.30 million related to our proved oil and gas properties.

General and administrative expenses. General and administrative expenses were $21.72 million ($0.93 per Mcfe) for the year ended December 31, 2006, an increase of $10.41 million (92%) from $11.31 million ($1.62 per Mcfe) for the year ended December 31, 2005. Non-cash stock-based compensation was $9.14 million during the year ended December 31, 2006 and $3.25 million during the year ended December 31, 2005. General and administrative expenses, excluding non-cash stock-based compensation, (Net general expense) were $12.58 million ($0.54 per Mcfe) for the year ended December 31, 2006, an increase of $4.52 million (56%) from $8.06 million ($1.15 per Mcfe) for the year ended December 31, 2005. The increase in Net general expenses during 2006 was primarily due to the hiring of additional staff and an increase in professional fees related to the combination transaction and other activities of our company. We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $0.80 million and $0.59 million during the years ended December 31, 2006 and 2005, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Interest expense. Interest expense was $30.57 million for the year ended December 31, 2006, an increase of $27.47 million from $3.10 million for the year ended December 31, 2005. The weighted average interest rate for the years ended December 31, 2006 and 2005 was 7.5% and 5.5%, respectively. The weighted average debt outstanding during 2006 and 2005 was approximately $406.78 million and $59.26 million, respectively. The increase in interest expense was due to the increase in overall debt outstanding and the increase in interest rates. The increase in weighted average debt outstanding during 2006 was primarily due to our borrowing under our revolving credit facility on February 27, 2006 to fund the cash payment due as part of the combination transaction, to repay the Concho Equity Holdings Corp. credit facility, and to pay bank and legal fees. The increase in weighted average debt outstanding was also due to our borrowing $40.00 million under our prior second lien term loan facility on July 6, 2006 to reduce the amount outstanding under our revolving credit facility by $32.10 million, with the remaining $7.90 million used for general corporate purposes.

Other, net. Interest and other revenue was $1.19 million during the year ended December 31, 2006, an increase of $0.41 million from $0.78 million during the year ended December 31, 2005. Interest earned was

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$0.82 million during the year ended December 31, 2006, an increase of $0.45 million from $0.37 million during the year ended December 31, 2005, due to interest on officer and employee notes. Other revenue was $0.37 million during the year ended December 31, 2006, a decrease of $0.04 million from $0.41 million during the year ended December 31, 2005.

Income tax provisions (benefits). We recorded income tax expense of $14.38 million and $2.04 million for the years ended December 31, 2006 and 2005, respectively. The income tax expense was due to the income reported during the years ended December 31, 2006 and 2005.

At December 31, 2006, we had a net deferred tax liability of $241.67 million. This change is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006, a reduction of deferred hedge losses and the elimination of the net operating loss. We had a net deferred federal and state tax asset at December 31, 2005 in the amount of $4.90 million. This accumulated balance is based on deferred hedge losses and differences in basis of oil and gas properties for tax purposes as compared to book purposes and offset by the effect of a net operating loss. Intangible drilling costs are allowed as deductions by the Internal Revenue Service and are capitalized under the generally accepted accounting principles in the United States of America.

Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facilities. We believe that funds from operating cash flows and our bank credit facilities should be sufficient to meet both our short-term working capital requirements and our 2008 exploration and development budget.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $169.77 million, $112.18 million and $25.07 million for the years ended December 31, 2007, 2006 and 2005, respectively. The increase in operating cash flows during the year ended December 31, 2007 over 2006 was principally due to increases in our oil and gas production as a result of our exploration and development program and cash flow from production attributable to the Chase Group Properties that we acquired in the combination transaction in February 2006. The increase in operating cash flows in 2006 over 2005 was principally due to increases in our oil and gas production as a result of our exploration and development program and cash flow from production attributable to the Chase Group Properties that we acquired in the combination transaction in February 2006.

Cash Flow Used in Investing Activities

During the years ended December 31, 2007, 2006 and 2005, we invested $162.63 million, $595.62 million and $55.62 million, respectively, for additions to, and acquisitions of, oil and gas properties, inclusive of dry hole costs. Cash flows used in investing activities were substantially higher during the year ended December 31, 2006, primarily due to the approximately $409.00 million cash portion of the consideration we paid to the Chase Group in the combination transaction and drilling activities in 2006. In order to preserve liquidity, we reduced our drilling activities and curtailed capital expenditures during the three months ended March 31, 2007, until we were able to complete our second lien term loan facility in March 2007. As a result, we recorded an expense during the six months ended June 30, 2007 of approximately $4.27 million for contract drilling fees related to stacked rigs subject to day work drilling contracts with two drilling contractors including Silver Oak Drilling. See Items Impacting Comparability of our Financial Results Curtailment of Drilling above.

Cash Flow from Financing Activities

Net cash provided by financing activities was $19.89 million, $476.61 million and $45.36 million for the years ended December 31, 2007, 2006 and 2005, respectively. In March 2007, we entered into a $200.00 million second lien term loan facility. The proceeds were principally used to repay the outstanding balance under our prior term loan facility and to reduce the outstanding balance under our revolving credit facility. In August 2007, we completed an initial public of our common stock. The aggregate net proceeds of approximately $173.00 million received by us were utilized in equal parts to repay a portion of the New 2nd Lien Credit Facility on August 9, 2007, and to prepay a portion of the 1st Lien Credit Facility on August 20, 2007. Cash provided by financing activities during the year ended December 31, 2006 was primarily due to borrowings under our revolving credit facility to fund the approximately $409.00 million cash portion of the consideration paid to the Chase Group pursuant to the combination transaction and proceeds from private issuances of equity in our company. In 2005, cash provided by financing activities was primarily attributable to net proceeds from the issuance of debt and equity in our company, partially offset by payment of dividends on preferred stock. The increase during 2006 was primarily due to borrowings under our revolving credit agreement to fund the approximately $409.00 million cash portion of the consideration paid to the Chase Group and associated persons pursuant to the combination transaction and proceeds from private issuances of equity in our company.

Bank Credit Facilities

We have two separate bank credit facilities. The first is our credit facility agreement, dated February 24, 2006, with JPMorgan Chase Bank, N.A. as the administrative agent for a group of lenders that provides a revolving line of credit having a total commitment of $475.00 million, which we refer to as our 1st Lien Credit Facility. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of the total commitment of $475.00 million or the borrowing base established by the lenders. As of December 31, 2006, the borrowing base under our 1st Lien Credit Facility was $475.00 million, but was reduced to $375.00 million on March 27, 2007 in connection with the completion of our New 2nd Lien Credit Facility described below. Effective November 21, 2007, in conjunction with the regular redetermination as of June 30, 2007, the borrowing base under our 1st Lien Credit Facility was increased to $425.00 million. In February 2006, we incurred borrowings of approximately $421.00 million under our 1st Lien Credit Facility in connection with the combination transaction to pay the cash purchase price of $400.00 million to the Chase Group, $15.90 million to repay the balance on the prior revolving credit facility of Concho Equity Holdings Corp. and approximately $5.10 million for bank fees and legal costs associated with our 1st Lien Credit Facility. We also incurred borrowings of approximately $8.90 million in May 2006 in connection with the purchase of additional working interests in the Chase Group Properties pursuant to the combination transaction from persons associated with the Chase Group. The remaining borrowings under our 1st Lien Credit Facility during 2006 were used for working capital and to fund a portion of our exploration and development drilling program. During 2007, the outstanding balance on our 1st Lien Credit Facility was reduced by $239.70 million from $455.70 million at December 31, 2006 to $216.00 million at December 31, 2007. This reduction is the result of repayments we made with net proceeds of $154.00 million from our New 2nd Lien Credit Facility in March 2007 and the proceeds of $86.50 million from the initial public offering in August 2007.

The second bank credit facility is our term loan agreement, dated March 27, 2007, with Bank of America, N.A., as the administrative agent for the other lenders thereunder, that provides a five year term loan in the amount of $200.0 million, the New 2nd Lien Credit Facility. Upon execution of the New 2nd Lien Credit Facility, we funded the full amount under that facility and received proceeds of $199.00 million to repay the $39.80 million outstanding under our 2nd Lien Credit Facility, to reduce the outstanding balance under our 1st Lien Credit Facility by $154.00 million and the remaining $5.20 million to pay loan fees, accrued interest and for general corporate purposes. We used net proceeds of approximately $173.00 million from our initial public offering that was completed in August 2007 to retire outstanding borrowings under our New 2nd Lien Credit Facility totaling $86.50 million and to retire outstanding borrowings under our 1st Lien Credit Facility totaling $86.50 million.

1st Lien Credit Facility. The 1st Lien Credit Facility allows us to borrow, repay and reborrow amounts available under the borrowing base. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base under our 1st Lien Credit Facility is re-determined at least semi-annually. The 1st Lien Credit Facility matures on February 24, 2010, and borrowings bear interest, payable quarterly, at our option, at (1) a rate (as defined and further described in our revolving credit facility) per annum equal to a Eurodollar Rate (which is substantially the same as the London Interbank Offered Rate) for one, two, three or six months as offered by the lead bank under our 1st Lien Credit Facility, plus an applicable margin ranging from 100 to 225 basis points, or (2) such bank s Prime Rate, plus an applicable margin ranging from 0 to 125 basis points, dependent in each case upon the percentage of our available borrowing base then utilized. Our 1st Lien Credit Facility bore interest at 6.16% per annum as of December 31, 2007. We pay quarterly commitment fees under our 1st Lien Credit Facility on the unused portion of the available borrowing base ranging from 25 to 50 basis points, dependent upon the percentage of our available borrowing base then utilized.

Borrowings under our 1st Lien Credit Facility are secured by a first lien on substantially all of our assets and properties. Our 1st Lien Credit Facility also contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers involving our company, incur liens and engage in certain other transactions without the prior consent of the lenders. The 1st Lien Credit Facility also requires us to maintain certain ratios as defined and further described in our 1st Lien Credit Facility agreement, including a current ratio of not less than 1.0 to 1.0 and a maximum leverage ratio (generally defined as the ratio of total funded debt to a defined measure of cash flow) of no greater than 4.0 to 1.0. In addition, at the inception of the 1st Lien Credit Facility, we had a one-time requirement to enter into hedging agreements (as defined in our 1st Lien Credit Facility agreement, but not necessarily accounted for as cash flow hedges in our financial statements) with respect to not less than 75% of our forecasted production through December 31, 2008, that was attributable to our proved developed producing reserves estimated as of December 31, 2005. As of December 31, 2007, we were in compliance with all such covenants.

New 2nd Lien Credit Facility. The New 2nd Lien Credit Facility provides a $200.00 million term loan, which bears interest, at our option, at (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 425 basis points or (2) the prime rate, plus an applicable margin of 275 basis points. We have the option to select different interest periods, subject to availability, and interest is payable at the end of the interest period we select, though such interest payments must be made at least on a quarterly basis. We are required to repay $0.50 million of the outstanding balance on the last day of each calendar quarter, commencing June 30, 2007, until the remaining balance of the loan matures on March 27, 2012. Our New 2nd Lien Credit Facility bore interest at 9.23% per annum as of December 31, 2007. We have the right to prepay the outstanding balance at any time, provided, however, that we will incur a 2% prepayment penalty on any principal amount prepaid from March 27, 2008 until March 26, 2009 and a 1% prepayment penalty on any principal amount prepaid from March 27, 2009 until March 26, 2010.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing our 1st Lien Credit Facility, and are subordinated to liens securing our 1st Lien Credit Facility. The New 2nd Lien Credit Facility also contains various restrictive financial covenants and compliance requirements that are similar to those contained in the 1st Lien Credit Facility, including the maintenance of certain financial ratios.

Future Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and gas properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise or that otherwise have geologic characteristics that are similar to our existing properties.

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We invested approximately $183.0 million for exploration and development expenditures in 2007 as follows (in millions):

	Amount
Drilling and recompletion opportunities in our core operating area	$ 135.2
Projects in our emerging plays	28.9

Projects operated by third parties		14.2
Acquisition of leasehold acreage and other property interests		4.7
Total 2007 exploration and development expenditures	$	183.0

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On November 8, 2007, our board of directors approved our 2008 exploration and development budget in the amount of $250.4 million. We anticipate investing our 2008 exploration and development budget as follows (in millions):

	2008 Budget
Drilling and recompletion opportunities in our core operating areas	$ 209.5
Projects operated by third parties	14.3
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical	20.0
Maintenance capital in our core operating areas	6.6
Total 2008 exploration and development budget	$ 250.4

Other than leasehold acreage and other property interests shown above, our 2007 and 2008 exploration and development budgets are exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2008 exploration and development budget; however, we could use our revolving credit facility to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. In addition, under certain circumstances we would consider increasing or reallocating our 2008 capital budget.

Commodity Derivatives and Hedging

We account for derivative instruments in accordance with SFAS No. 133. The specific accounting treatment for changes in the market value of the derivative instruments is determined based on whether we designate the derivative instruments as a cash flow or fair value hedge and effectiveness of the hedge. Certain of our derivative contracts related to oil production entered into prior to 2007 are accounted for as cash flow hedges. As described below, certain natural gas derivative contracts were originally designated as cash flow hedges, but because of a change in the correlation between the underlying natural gas production and the index referenced in the derivative contracts, we have discontinued hedge accounting related to natural gas contracts as of July 1, 2007. Management has not and does not currently intend to designate or account for derivative contracts entered into subsequent to June 30, 2007 as cash flow hedges.

We have utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts, we receive the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil or natural gas, as applicable, is less than the ceiling strike price and greater than the floor strike price, we receive the market price. If the market price of crude oil or natural gas, as applicable, exceeds the ceiling strike price or falls below the floor strike price, we receive the applicable collar strike price.

As of June 30, 2007, we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133, for the reason stated in the following paragraph. These contracts are referred to as dedesignated hedges.

A key requirement for designation of derivative instruments as cash flow hedges is that at both the inception of the hedge and on an ongoing basis, the hedging relationship is expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Generally, the hedging relationship can be considered to be highly effective if there is a high degree of historical correlation between the hedging instrument and the forecasted transaction. In prior periods and through June 30, 2007, prices received for our natural gas were highly correlated with the Inside FERC El Paso Natural Gas index, which we refer to herein as the Index, which is the index referenced in all of our natural gas derivative instruments. However, subsequent to June 30, 2007, this historical relationship has not met the criteria as being highly correlated. Natural gas produced from our New Mexico Shelf assets has a substantial component of natural gas liquids. Prices received for natural gas liquids are not highly correlated to the price of natural gas, but are more closely correlated to the price of oil. During the third quarter of 2007, the price of oil and natural gas liquids, and therefore the prices we received for our natural gas (including natural gas liquids), rose substantially and at a significantly higher rate than the corresponding change in the Index. This resulted in a decrease in correlation between the prices received and the Index below the level required for cash flow hedge accounting. According to SFAS No. 133, an entity should discontinue prospectively hedge accounting for an existing hedge if the hedge is no longer highly effective. Hedge accounting must be discontinued regardless of whether we believe the hedge will be prospectively highly effective. The hedge must be discontinued during the period the hedges became ineffective. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges* . Because the natural gas and natural gas liquids prices fluctuate at different rates over time, the loss of effectiveness does not relate to any single date.

June 30, 2007 is considered the last date our natural gas hedges were highly effective, and we have discontinued hedge accounting during the six months ended December 31, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges are recorded each period to *(Gain) loss on derivatives not designated as hedges*. Effective portions of dedesignated hedges, previously recorded in *Accumulated other comprehensive income* as of June 30, 2007, will remain in *Accumulated other comprehensive income* and be reclassified into earnings under *Natural gas revenues*, during the periods which the hedged forecasted transaction affects earnings.

We do not intend to attempt to re-designate these natural gas derivatives as cash flow hedges in future periods; rather, they will be accounted for as described above through the remaining derivative contract term.

On September 20, 2007, we entered into four crude oil price swaps to hedge an additional portion of our estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,000 Bbls per day each with various fixed prices. We have not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

At December 31, 2007, we had oil price swaps that settle on a monthly basis covering future oil production from January 1, 2008 through December 31, 2009. The volumes are detailed in the table below. Subsequent to December 31, 2007, oil futures prices have increased significantly and have risen to a level that exceeds the weighted average price swap fixed price of $78.45. The average futures NYMEX price for the year ended December 31, 2007, was $72.39. As of March 27, 2008, the NYMEX futures price was $107.58. At this level, we will continue to remit the excess of the average monthly NYMEX futures price for each settlement period over the weighted average price swap fixed price of $78.45. These payments should not significantly affect our cash flow since (1) payments made to counterparties to these contracts should be substantially offset by increased commodity prices received on the sale of our production and (2) only a portion of the total contract volume settles each month. The increase in oil prices, should it continue, will negatively affect the fair value of our commodities contracts as recorded in our balance sheet at March 31, 2008, during future periods and, consequently, our reported net income. Changes in the recorded fair value of certain of our commodity derivatives are marked to market through earnings and are likely to result in substantial charges to earnings for the decrease in the fair value of these contracts during the first quarter of 2008. If oil prices continue to increase, this negative effect on earnings will become more significant. We are currently unable to estimate the effects on earnings in the first quarter of 2008, but the effects may be substantial.

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The table below provides the volumes and related data associated with our oil and natural gas derivatives as of December 31, 2007:

	Fair Market Value Asset/(Liability)	Aggregate Remaining Volume	Daily Volume	Index Price	Contract Period
			(In thousands)		
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(23,942)	951,600	2,600	$67.50(a)	1/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	1,866	4,941,000	13,500	$6.50 - $9.35(b)	1/1/08 - 12/31/08
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(12,472)	732,000	2,000	$75.78(a)(c)	1/1/08 - 12/31/08
Price swap	(10,517)	730,000	2,000	$72.84(a)(c)	1/1/09 - 12/31/09
Net liability	$ (45,065)				

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

Obligations and Commitments

We had the following contractual obligations and commitments as of December 31, 2007:

	Payments Due by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
			(In thousands)		
Long-term debt(a)	$ 327,900	$ 2,000	$ 220,000	$ 105,900	$
Operating lease obligation(b)	3,040	497	1,026	1,068	449

Daywork drilling contracts(c)	14,774	14,774			
Employment agreements with executive officers(d)	3,003	1,925	1,078		
Asset retirement obligations(e)	9,418	912	349	114	8,043
Total contractual cash obligations	$ 358,135	$ 20,108	$ 222,453	$ 107,082	$ 8,492

(a) See Note J *Long-term debt* to our consolidated financial statements.

(b) Represents office space for our headquarters in Midland, Texas.

(c) Consists of daywork drilling contracts related to five drilling rigs contracted for a portion of 2007 and a portion of 2008. See Note K *Commitments and contingencies* to our consolidated financial statements.

(d) Represents amounts of cash compensation we are obligated to pay to our executive officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted. Effective March 1, 2008, Messrs. Leach and Beal each received an annual pay increase of $100,000. An executive officer resigned as of March 31, 2008, and the Company will be obligated to pay such person 1/12th of his base salary for each month from April 2008 through March 2009 as consideration for such person s covenant not to compete with the Company in accordance with his employment agreement.

(e) Amounts represent costs related to expected oil and gas property abandonments related to proved reserves by period, net of any future accretion.

Off-balance Sheet Arrangements

Currently we do not have any off-balance sheet arrangements.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities under this method. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are also capitalized. This accounting method may yield significantly different results than the full cost method of accounting. Exploratory drilling costs are initially capitalized, but are charged to expense if and when the well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing properties are sold.

The application of the successful efforts method of accounting requires management s judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and gas leasehold acquisition costs included in unproved properties requires management s judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively condemn our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value.

Depreciation of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on an individual property or unit basis based on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated net proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 1 to 50 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Future Cash Flows

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved oil and natural gas reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future DD&A and result in impairment of assets that may be material.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this standard on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. SFAS No. 143 requires us to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We adopted SFAS No. 157 effective January 1, 2008, and it has had no material impact on our consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, which will become effective in 2008. SFAS No. 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. We adopted this statement January 1, 2008 and did not elect the fair value option for any of its eligible financial instruments or other items. As such, the adoption had no impact on the consolidated financial statements.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FIN No. 39-1). FIN No. 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FIN No. 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Adoption of FIN No. 39-1 is not expected to have a material impact on our consolidated financial statements.

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The consensus in EITF Issue 06-11 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2007. Retrospective application of EITF Issue 06-11 is not permitted. Early adoption is permitted; however, we do not intend to adopt EITF Issue 06-11 prior to the required effective date of January 1, 2008. We do not expect the adoption of EITF Issue 06-11 to have a significant effect on our financial statements since we historically have accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), which replaces FASB Statement No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non- controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be our fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51. SFAS No. 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be our fiscal year 2009. Based upon our December 31, 2007 balance sheet, the statement would have no impact.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

Item 7A. *Quantitative and Qualitative Disclosure About Market Risk*

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments.

Hypothetical changes in interest rates and prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries, as described under Item 1. Business Marketing Arrangements. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future.

Commodity price risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. As of December 31, 2007, the net unrealized loss on our commodity price risk management contracts was $45.1 million. An average increase in the commodity price of $1.00 per barrel of crude oil and $0.10 per Mcf for natural gas from the commodity prices as of December 31, 2007, would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet as of December 31, 2007, of approximately $2.7 million.

At December 31, 2007, we had oil price swaps that settle on a monthly basis covering future oil production from January 1, 2008 through December 31, 2009. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Commodity Derivatives and Hedging. Subsequent to December 31, 2007, oil futures prices have increased significantly and continue to exceed the weighted average price swap fixed price of $78.45. The average futures NYMEX price for the year ended December 31, 2007, was $72.39. As of March 27, 2008, the NYMEX futures price was $107.58. At this level, we will continue to remit the excess of the average monthly NYMEX futures price for each settlement period over the weighted average price swap fixed price of $78.45. These payments should not significantly affect our cash flow since (1) payments made to counterparties to these contracts should be substantially offset by increased commodity prices received on the sale of our production and (2) only a portion of the total contract volume settles each month. The increase in oil prices, should it continue, will negatively affect the fair value of our commodities contracts as recorded in our balance sheet at March 31, 2008, during future periods and, consequently, our reported net income. Changes in the recorded fair value of certain of our commodity derivatives are marked to market through earnings and are likely to result in substantial charges to earnings for the decrease in the fair value of these contracts during the first quarter of 2008. If oil prices continue to increase, this negative effect on earnings will become more significant.

Interest rate risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our bank credit facilities, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. We had total indebtedness of $216.0 million outstanding under our revolving credit facility at December 31, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.2 million and a corresponding decrease in net income before income tax. As of December 31, 2007, we had $111.9 million of outstanding indebtedness under our second lien term loan facility. The impact of a 1% increase in interest rates on this amount of debt under our second lien term loan facility would result in increased interest expense of approximately $1.1 million and a corresponding decrease in net income before income tax.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements and supplementary financial data are included in this annual report beginning on page F-1.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

We had no changes in, and no disagreements with our accountants, on accounting and financial disclosure.

Item 9A(T). *Controls and Procedures*

Evaluation of disclosure controls and procedures. Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. This information is also accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the most recent fiscal year reported on herein. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2007, our disclosure controls and procedures were effective, in all material respects, to ensure that the information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

This annual report does not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2007.

Item 11. ***Executive Compensation.***

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act . The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2007.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.***

Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2007.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2007.

Item 14. ***Principal Accounting Fees and Services.***

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. The Registrant expects to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2007.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K***

Exhibit No.	Exhibit Title	Filed Herewith (*) or Incorporated by Reference to the Following
3.1	Restated Certificate of Incorporation	Form 8-K, filed August 8, 2007 (file no. 001-33615)
3.2	Amended and Restated Bylaws of Concho Resources Inc.	Form 8-K, filed March 26, 2008 (file no. 001-33615)
4.1	Specimen Common Stock Certificate	Form S-1/A, filed July 5, 2007 (file no. 333-142315)
10.1		

Credit Agreement dated February 24, 2006, among Concho Resources Inc., JPMorgan Chase Bank, N.A., as administrative agent, Bank of America, N.A., as syndication agent, Wachovia Bank, National Association, and BNP Paribas, as documentation agents, and other lenders party thereto	Form S-1, filed June 6, 2007 (file no. 333-142315)

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Exhibit No.	Exhibit Title	Filed Herewith (*) or Incorporated by Reference to the Following
10.2	Second Lien Credit Agreement dated March 23, 2007, among Concho Resources Inc., Bank of America, N.A., as administrative agent, and Banc of America LLC, as sole lead arranger and sole booking manager	Form S-1, filed June 6, 2007 (file no. 333-142315)
10.3	Form of Drilling Agreement with Silver Oak Drilling, LLC	Form S-1/A, filed July 5, 2007 (file no. 333-142315)
10.4	Salt Water Disposal System Ownership and Operating Agreement dated February 24, 2006, among COG Operating LLC, Chase Oil Corporation, Caza Energy LLC and Mack Energy Corporation	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.5	Transition Services Agreement dated April 23, 2007, between COG Operating LLC and Mack Energy Corporation	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.6	Combination Agreement dated February 24, 2006, among Concho Resources Inc., Concho Equity Holdings Corp., Chase Oil Corporation, Caza Energy LLC and the other signatories thereto	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.7	Software License Agreement dated March 2, 2006, between Enertia Software Systems and Concho Resources Inc.	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.8	Leasehold Acquisition Agreement dated April 1, 2005, by and between Trey Resources, Inc. and COG Oil and Gas LP	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.9	Transfer of Operating Rights (Sublease) in a Lease for Oil and Gas for Valhalla properties	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.10	Assignment of Oil and Gas Leases from Caza Energy LLC	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.11**	Escrow Agreement dated February 27, 2006, among Concho Resources Inc., Timothy A. Leach, Steven L. Beal, David W. Copeland, Curt F. Kamradt and E. Joseph Wright and the other signatories thereto	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.12	Business Opportunities Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.13	Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.14**	Concho Resources Inc. 2006 Stock Incentive Plan	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.15**	Concho Resources Inc. Summary of Executive Officer Compensation Program	*

10.16**	Form of Nonstatutory Stock Option Agreement	*
10.17**	Form of Restricted Stock Agreement (for employees)	Form S-1, filed April 24, 2007 (file no. 333-142315)

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Exhibit No.	Exhibit Title	Filed Herewith (*) or Incorporated by Reference to the Following
10.18**	Form of Restricted Stock Agreement (for non-employee directors)	*
10.19**	Employment Agreement dated July 14, 2006, between Concho Resources Inc. and Timothy A. Leach	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.20**	Employment Agreement dated July 14, 2006, between Concho Resources Inc. and Steven L. Beal	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.21**	Employment Agreement dated July 14, 2006, between Concho Resources Inc. and David W. Copeland	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.22**	Employment Agreement dated July 14, 2006, between Concho Resources Inc. and Curt F. Kamradt	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.23**	Employment Agreement dated July 14, 2006, between Concho Resources Inc. and David M. Thomas III	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.24**	Employment Agreement dated July 14, 2006, between Concho Resources Inc. and E. Joseph Wright	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.25**	Form of Indemnification Agreement	Form S-1, filed April 24, 2007 (file no. 333-142315)
10.26	Gas Purchase Contract between COG Oil & Gas LP and Duke Energy Field Services, LP dated November 1, 2006	Form S-1, filed June 6, 2007 (file no. 333-142315)
10.27	Letter Agreement between COG Operating LLC and Navajo Refining Company, L.P. dated January 15, 2007	Form S-1, filed June 6, 2007 (file no. 333-142315)
10.28	First Amendment to Credit Agreement, dated as of July 6, 2006, among Concho Resources Inc., certain of its subsidiaries, JPMorgan Chase Bank, N.A. and the other leaders party thereto	Form S-1, filed June 6, 2007 (file no. 333-142315)
10.29	Second Amendment to Credit Agreement, dated as of March 7, 2007, among Concho Resources Inc., certain of its subsidiaries, JPMorgan Chase Bank, N.A. and the other leaders party thereto	Form S-1, filed June 6, 2007 (file no. 333-142315)
10.30**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Leach and Beal	Form S-1, filed June 6, 2007 (file no. 333-142315)
10.31**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Copeland,	Form S-1, filed June 6, 2007 (file no. 333-142315)

	Kamradt, Thomas and Wright	
10.32**	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Timothy A. Leach	Form 8-K, filed August 24, 2007 (file no. 001-33615)

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Exhibit No.	Exhibit Title	Filed Herewith (*) or Incorporated by Reference to the Following
10.33**	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Steven L. Beal	Form 8-K, filed August 24, 2007 (file no. 001-33615)
10.34**	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and David W. Copeland	Form 8-K, filed August 24, 2007 (file no. 001-33615)
10.35**	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Curt F. Kamradt	Form 8-K, filed August 24, 2007 (file no. 001-33615)
10.36**	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and E. Joseph Wright	Form 8-K, filed August 24, 2007 (file no. 001-33615)
10.37**	First Amendment to Employment Agreement, dated August 31, 2007, by and between Concho Resources Inc. and David M. Thomas III	Form 10-Q, filed September 10, 2007 (file no. 001-33615)
10.38**	Form of Amendment to Stock Option Award Agreement with executive officers related to the Pre-Combination Options	Form 8-K, filed November 20, 2007 (file no. 001-33615)
10.39**	Form of Amendment to Nonstatutory Stock Option Agreement with executive officers related to the June 2006 Options	Form 8-K, filed November 20, 2007 (file no. 001-33615)
10.40**	Form of Restricted Stock Agreement with executive officers related to the June 2006 Options	Form 8-K, filed November 20, 2007 (file no. 001-33615)
10.41**	Summary of Director Compensation Program	*
21.1	Subsidiaries of Concho Resources Inc.	Form S-1, filed June 6, 2007 (file no. 333-142315)
23.1	Consent of Grant Thornton LLP	*
23.2	Consent of Netherland, Sewell & Associates, Inc.	*
23.3	Consent of Cawley, Gillespie & Associates, Inc.	*
31.1	Section 302 Certification Chief Executive Officer	*
31.2	Section 302 Certification Chief Financial Officer	*
32.1	Section 906 Certification Chief Executive Officer	*
32.2	Section 906 Certification Chief Financial Officer	*

** Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONCHO RESOURCES INC.

By /s/ TIMOTHY A. LEACH

Timothy A. Leach
Director, Chairman of the Board of Directors and Chief Executive Officer

Date: March 28, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Director, Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	March 28, 2008
/s/ STEVEN L. BEAL Steven L. Beal	Director, President and Chief Operating Officer	March 28, 2008
/s/ CURT F. KAMRADT Curt F. Kamradt	Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 28, 2008
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	March 28, 2008
/s/ WILLIAM H. EASTER III William H. Easter III	Director	March 28, 2008
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	March 28, 2008
/s/ RAY M. POAGE Ray M. Poage	Director	March 28, 2008

/s/ A. WELLFORD TABOR	Director	March 28, 2008
A. Wellford Tabor		

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Glossary of Terms

The terms defined in this section are used throughout this annual report:

Bbl	One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.
Bcfe	One billion cubic feet of natural gas equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.
Basin	A large natural depression on the earth s surface in which sediments accumulate.
Development wells	Wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
Dry hole	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.
Exploitation	A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally is reasonably expected to have lower risk.
Exploratory wells	Wells 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.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
Gross wells	The number of wells in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.
Infill wells	Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.
MBbl	One thousand barrels of crude oil, condensate or natural gas liquids.

Mcf	One thousand cubic feet of natural gas.
Mcfe	One thousand cubic feet of natural gas equivalent.
MMBbl	One million barrels of crude oil, condensate or natural gas liquids.
MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.
MMcfe	One million cubic feet of natural gas equivalent.
NYMEX	The New York Mercantile Exchange.

Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.
Net revenue interest	A working interest owner s gross working interest in production, less the related royalty, overriding royalty, production payment, and net profits interests.
Net wells	The total of fractional working interests owned in gross wells.
PV-10	When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC.
Primary recovery	The period of production in which oil and natural gas is produced from its reservoir through the wellbore without enhanced recovery technologies, such as water flooding or gas injection.
Productive wells	Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.
Proved developed reserves	Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as: 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 reserves	Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as: 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.

(i) Reservoirs are considered proved if economic producibility 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

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	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 undrilled 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 undeveloped reserves	Has the meaning given to such term in Rule 4-10(a)(4) of Regulation S-X, which defines proved undeveloped reserves as: 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 undrilled 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.
Recompletion	The addition of production from another interval or formation in an existing wellbore.
Reservoir	A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.
Secondary recovery	The recovery of oil and gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Secondary recovery methods are often applied when production slows due to depletion of the natural pressure.

Seismic survey	Also known as a seismograph survey, is a survey of an area by means of an instrument which records the travel time of the vibrations of the earth. By recording the time interval between the source of the shock wave and the reflected or refracted shock waves from various

	formations, geophysicists are better able to define the underground configurations.
Spacing	The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.
Standardized measure	The present value (discounted at an annual rate of 10%) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with Statement of Financial Accounting Standards No. 69 (using prices and costs in effect as of the period end date) without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.
Step-out drilling	The drilling of a well adjacent to existing production in an effort to expand the aerial extent of a known producing field.
Undeveloped acreage	Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Unit	The joining of all or substantially all interests in a reservoir or field, rather than single tracts, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
Wellbore	The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.
Working interest	The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
Workover	Operations on a producing well to restore or increase production.

Index to consolidated financial statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Concho Resources Inc.

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries, formerly Concho Equity Holdings Corp., as of December 31, 2007 and 2006, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2007. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purposes of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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 Concho Resources Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

March 25, 2008
Tulsa, Oklahoma

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Concho Resources Inc. and subsidiaries

Consolidated balance sheets

	December 31, 2007	December 31, 2006
	(In thousands, except share and per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 30,424	$ 1,122
Accounts receivable:		
Oil and gas	36,735	27,304
Joint operations and other	21,183	22,638
Related parties		1,449
Assets held for sale	256	
Derivative instruments	1,866	6,013
Deferred income taxes	13,502	82
Inventory	1,459	1,309
Prepaid insurance and other	4,017	3,848
Total current assets	109,442	63,765
Property and equipment, at cost:		
Oil and gas properties, successful efforts method	1,555,018	1,399,218
Accumulated depletion and depreciation	(167,109)	(84,098)
Total oil and gas properties, net	1,387,909	1,315,120
Other property and equipment, net	7,085	5,535
Total property and equipment, net	1,394,994	1,320,655
Deferred loan costs, net	3,426	4,417
Other assets	367	1,235
Total assets	$ 1,508,229	$ 1,390,072
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 14,222	$ 16,157
Related parties	2,119	3,593
Other current liabilities:		
Bank overdrafts	5,651	
Revenue payable	14,494	9,901
Accrued drilling costs	39,276	17,051

Accrued interest	1,590	8,004
Other accrued liabilities	11,964	6,220
Derivative instruments	36,414	6,224
Dividends payable		87
Chase Group unaccredited investors asset purchase obligation		906
Current portion of long-term debt	2,000	400
Current asset retirement obligations	912	1,958
Total current liabilities	128,642	70,501
Long-term debt	325,404	495,100
Noncurrent derivative instruments	10,517	
Deferred income taxes	259,070	241,752
Asset retirement obligations and other long-term liabilities	9,198	7,563
Commitments and contingencies (Note K)		
Stockholders equity:		
6% Series A preferred stock, $0.01 par value; 30,000,000 shares authorized; and zero shares issued and outstanding at December 31, 2007 and 2006		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; and zero shares issued and outstanding at December 31, 2007 and 2006		
Common stock, $0.001 par value; 300,000,000 authorized; 75,832,310 and 59,092,830 shares issued and outstanding at December 31, 2007 and 2006, respectively	76	59
Additional paid-in capital	752,380	575,389
Notes receivable from officers and employees	(330)	(12,858)
Retained earnings	37,467	12,152
Accumulated other comprehensive income (loss)	(14,195)	414
Total stockholders equity	775,398	575,156
Total liabilities and stockholders equity	$ 1,508,229	$ 1,390,072

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

Concho Resources Inc. and subsidiaries

Consolidated statements of operations

	Year Ended December 31, 2007	2006	2005
	(In thousands, except per share amounts)		
Operating revenues:			
Oil sales	$ 195,596	$ 131,773	$ 31,621
Natural gas sales	98,737	66,517	23,315
Total operating revenues	294,333	198,290	54,936
Operating costs and expenses:			
Oil and gas production	29,966	22,060	10,923
Oil and gas production taxes	24,301	15,762	3,712
Exploration and abandonments	29,098	5,612	2,666
Depreciation and depletion	76,779	60,722	11,485
Accretion of discount on asset retirement obligations	444	287	89
Impairments of proved oil and gas properties	7,267	9,891	2,295
Contract drilling fees stacked rigs	4,269		
General and administrative (including non-cash stock-based compensation of $3,841, $9,144 and $3,252 for the years ended December 31, 2007, 2006 and 2005, respectively)	25,177	21,721	11,307
Ineffective portion of cash flow hedges	821	(1,193)	1,148
Loss on derivatives not designated as hedges	20,274		5,001
Total operating costs and expenses	218,396	134,862	48,626
Income from operations	75,937	63,428	6,310
Other income (expense):			
Interest expense	(36,042)	(30,567)	(3,096)
Other, net	1,484	1,186	779
Total other expense	(34,558)	(29,381)	(2,317)
Income before income taxes	41,379	34,047	3,993
Income tax expense	(16,019)	(14,379)	(2,039)
Net income	25,360	19,668	1,954
Preferred stock dividends	(45)	(1,244)	(4,766)
Effect of induced conversion of preferred stock		11,601	
Net income (loss) applicable to common shareholders	$ 25,315	$ 30,025	$ (2,812)
Basic earnings (loss) per share:			

Net income (loss) per share	$ 0.39	$ 0.63	$ (0.70)
Weighted average shares used in basic earnings (loss) per share	64,316	47,287	4,059
Diluted earnings (loss) per share:			
Net income (loss) per share	$ 0.38	$ 0.59	$ (0.70)
Weighted average shares used in diluted earnings (loss) per share	66,309	50,729	4,059

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

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Concho Resources Inc. and subsidiaries

Consolidated statements of stockholders equity

	6% Series A Preferred Stock		Common Stock		Additional Paid-In	Notes Receivable from Officers and	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Total Stockholder
	Shares	Amount	Shares	Amount	Capital	Employees	Deficit)	(Loss)	Equity
					(In thousands)				
ALANCE AT ECEMBER 31, 2004	7,689	$ 77	4,850	$ 5	$ 78,939	$ (3,884)	$ (3,460)	$ 33	$ 71,710
omprehensive income oss)									
et income							1,954		1,954
eferred hedge losses, et of tax benefit of 6,550								(12,147)	(12,147
et settlement losses cluded in earnings, net f taxes of $568								1,054	1,054
otal comprehensive ss									(9,139
suance of subscribed nits	5,270	53	2,635	2	53,029	(4,805)			48,279
suance of common ock			657	1	656				657
tock-based ompensation for stock ptions					1,506				1,506
tock-based ompensation on suance of units					1,746				1,746
ccrued interest fficer & employee otes						(323)			(323
% Series A Preferred ock dividends							(4,766)		(4,766
ALANCE AT ECEMBER 31, 2005	12,959	130	8,142	8	135,876	(9,012)	(6,272)	(11,060)	109,670
omprehensive income									
et income							19,668		19,668
								7,736	7,736

eferred hedge gains, et of tax of $4,200									
et settlement losses cluded in earnings, net f taxes of $2,030								3,738	3,738
otal comprehensive come									31,142
suance of subscribed nits	4,518	45	2,259	2	45,329	(3,158)			42,218
suance of common ock			578	1	577				578
onversion of preferred ock	(17,477)	(175)	13,106	13	162				
suance of common ock for acquisition			34,795	35	384,301				384,336
estricted stock issued s stock-based ompensation			214		1,044				1,044
ancellation of estricted stock			(1)						
tock-based ompensation for stock ptions					7,125				7,125
tock-based ompensation on suance of units					975				975
ccrued interest officer nd employee notes						(688)			(688
% Series A preferred ock dividends							(1,244)		(1,244
ALANCE AT ECEMBER 31, 2006			59,093	59	575,389	(12,858)	12,152	414	575,156
omprehensive income									
et income							25,360		25,360
eferred hedge losses, et of tax benefit of 13,204								(20,579)	(20,579
et settlement losses cluded in earnings, net f taxes of $3,830								5,970	5,970
otal comprehensive come									10,751
estricted stock issued s stock-based ompensation			138		1,378				1,378
ancellation of estricted stock			(2)						
					2,463				2,463

tock-based ompensation for stock ptions							
mendment of certain utstanding stock ptions due to 409A nodification	83		(192)				(192
suance of common ock for acquisition bligation	54		650				650
et proceeds from nitial public equity ffering	16,466	17	172,692				172,709
roceeds from notes eceivable officers and nployees				12,830			12,830
ccrued interest officer nd employee notes				(302)			(302
% Series A preferred ock dividends					(45)		(45
ALANCE AT ECEMBER 31, 2007	$ 75,832	$ 76	$ 752,380	$ (330)	$ 37,467	$ (14,195)	$ 775,398

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

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Concho Resources Inc. and subsidiaries

Consolidated statements of cash flows

	2007	Year Ended December 31, 2006 (In thousands)	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 25,360	$ 19,668	$ 1,954
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and depletion	76,779	60,722	11,485
Impairments of proved oil and gas properties	7,267	9,891	2,295
Accretion of discount on asset retirement obligations	444	287	89
Exploration expense, including dry holes	25,009	3,387	1,549
Non-cash compensation expense	3,841	9,144	3,252
Amendment of certain outstanding stock options due to 409A modification	(192)		
Gas imbalances	14	82	(37)
Deferred rent liability	(211)	262	11
Deferred income taxes	13,716	12,618	1,974
Interest accrued on officer and employee notes	(302)	(688)	(323)
Amortization of deferred loan costs	3,563	1,494	134
Amortization of discount on long-term debt	504		
(Gain) loss on sale of property and equipment	(368)	(3)	21
Ineffective portion of cash flow hedges	821	(1,193)	1,148
(Gain) loss on derivatives not designated as hedges	20,274		5,001
Dedesignated cash flow hedges reclassed from AOCI	(1,103)		
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(5,759)	(27,683)	(15,621)
Prepaid insurance and other	(319)	(2,465)	(1,548)
Other assets		12	
Accounts payable	(3,493)	13,853	3,452
Revenue payable	4,593	2,372	6,958
Accrued liabilities	5,745	3,101	2,786
Accrued interest	(6,414)	7,320	490
Net cash provided by operating activities	169,769	112,181	25,070
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on oil and gas properties	(162,378)	(182,389)	(52,768)
Acquisition of oil and gas properties and other assets	(255)	(413,229)	(2,855)
Additions to other property and equipment	(2,813)	(1,234)	(4,061)
Proceeds from the sale of oil and gas properties	3,255		
Proceeds from the sale of other assets	23		817
Settlements (paid) received on derivatives not designated as hedges	1,815		(3,035)

Net cash used in investing activities		(160,353)		(596,852)		(61,902)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from issuance of long-term debt		300,200		664,993		63,400
Payments of long-term debt		(468,800)		(241,493)		(44,400)
Proceeds from issuance of subscribed units and common stock		172,709		61,178		30,621
Payments of preferred stock dividends		(132)		(2,567)		(4,160)
Proceeds from repayment of officer and employee notes		12,830				
Payments for loan origination costs		(2,572)		(5,500)		(103)
Bank overdrafts		5,651				
Net cash provided by financing activities		19,886		476,611		45,358
Net increase (decrease) in cash and cash equivalents		29,302		(8,060)		8,526
BEGINNING CASH AND CASH EQUIVALENTS		1,122		9,182		656
ENDING CASH AND CASH EQUIVALENTS	$	30,424	$	1,122	$	9,182
SUPPLEMENTAL CASH FLOWS:						
Cash paid for interest and fees, net of $2,647, $2,129 and $370 capitalized interest	$	(34,623)	$	(23,881)	$	(2,449)
Cash paid for income taxes	$	(2,050)	$	(1,725)	$	(100)
NON-CASH INVESTING AND FINANCING ACTIVITIES:						
Issuance of common stock in acquisition of oil and gas properties and other assets	$	650	$	384,336	$	
Deferred tax effect of acquired oil and gas properties	$	(444)	$	227,735	$	
Issuance of notes receivable in connection with capital options	$		$	3,158	$	4,805

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

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Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements
December 31, 2007, 2006 and 2005

Note A. Organization and nature of operations

Concho Resources Inc. (Resources) is a Delaware corporation formed by Concho Equity Holdings Corp. (CEHC) on February 22, 2006, for purposes of effecting the combination of CEHC, Chase Oil Corporation, Caza Energy LLC (Caza) and certain other parties thereto (collectively with Chase Oil Corporation and Caza, the Chase Group). Pursuant to the Combination Agreement dated February 24, 2006, Resources acquired working interests in oil and natural gas properties from the Chase Group and issued shares of its common stock to certain stockholders of CEHC in exchange for their capital stock of CEHC. CEHC is a Delaware corporation formed on April 21, 2004 by certain individuals and private equity investors. CEHC commenced substantial oil and gas operations in December 2004 upon its acquisition of certain oil and gas properties located in Southeast New Mexico and West Texas. The combination transaction described above (the Combination) was accounted for as an acquisition by CEHC of the Chase Group properties and a simultaneous reorganization of Resources such that CEHC is now a wholly owned subsidiary of Resources. Prior to the Combination, Resources had no assets, operations or net equity. Upon the closing of the Combination, the executive officers of CEHC became the executive officers of Resources. Resources and its wholly owned subsidiaries are hereafter collectively referred to as the Company.

CEHC s shareholders received 23,767,691 shares of common stock of Resources in exchange for their preferred and common shares of CEHC, excluding eighteen holders owning an aggregate of 254,621 shares of CEHC 6% Series A Preferred Stock and 127,313 shares of CEHC common stock, as discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes*. In addition, the Chase Group transferred their ownership in certain oil and gas properties in Southeast New Mexico to Resources in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of Resources common stock. In connection with the Company s initial public offering and secondary public offering (both described below), the Chase Group sold a total of 18,638,014 shares of common stock thereby reducing its ownership interest. As of December 31, 2007 and December 31, 2006, the ownership of the Chase Group represented approximately 21 percent and 59 percent, respectively, of the total outstanding common stock ownership of the Company.

The Company s principal business is the acquisition, development, exploitation and exploration of oil and gas properties in the Permian Basin region of Southeast New Mexico and West Texas.

Initial public offering. On August 7, 2007 the Company completed an initial public offering (the IPO) of its common stock. The Company sold 13,332,851 shares and certain shareholders, including our executive officers and members of the Chase Group, sold 7,554,256 shares of Resources common stock, in each case, at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.5 million, the Company received net proceeds of approximately $139.2 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,133,066 additional shares of Resources common stock. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.2 million, the Company received net proceeds of approximately $33.8 million. The aggregate net proceeds of approximately $173.0 million received by the Company at closing on August 7, 2007 and August 9, 2007 were utilized in equal amounts to repay a portion of its term loan facility on August 9, 2007, and to prepay a portion of its revolving credit facility on August 20, 2007. See further discussion in Note J *Long-term debt*.

Secondary public offering. On December 19, 2007, the Company completed a secondary public offering of 11,845,000 shares of its common stock sold by certain of its stockholders, including members of the Chase group. The

Chase Group sold 10,194,732 shares in the aggregate and certain other stockholders sold 1,650,268 shares in the aggregate, including one of the Company s executive officers who sold 45,000 shares. Chase Oil Corporation has granted the underwriters an option to purchase up to 1,776,615 additional shares to cover over-allotments. The underwriters fully exercised this option and purchased the additional shares on December 19, 2007. The Company did not receive any proceeds from the sale of the shares sold in this secondary offering.

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

Reverse stock split. A one-for-two reverse stock split of the Company s outstanding common stock, which was approved by the Company s shareholders, became effective upon the completion of the Company s initial public offering. All common shares and per share amounts in the accompanying consolidated financial statements and notes to the consolidated financial statements have been retroactively adjusted for all periods presented to give effect to the reverse stock split.

Note B. Summary of significant accounting policies

Principles of consolidation. Prior to the Combination, the consolidated financial statements of Resources represent the accounts of CEHC and its wholly owned subsidiaries. After the Combination, the consolidated financial statements of Resources include the accounts of Resources and its wholly owned subsidiaries, including CEHC. All material intercompany balances and transactions have been eliminated.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion and depreciation of oil and gas properties are determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, the asset retirement obligations, fair value of derivative financial instruments, purchase price allocations for business and oil and gas property acquisitions and fair value of stock-based compensation.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company s cash and cash equivalents are held in a few financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company s counter-party risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. The Company sells oil and gas to various customers and participates with other parties in the drilling, completion and operation of oil and gas wells. Joint interest and oil and gas sales receivables related to these operations are generally unsecured. The Company determines joint interest operations accounts receivable allowances based on management s assessment of the creditworthiness of the joint interest owners and the Company s ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had no allowance for doubtful accounts at December 31, 2007 or 2006.

Assets held for sale. The Company capitalizes the costs of acquiring oil and gas leaseholds held for resale, including lease bonuses and any advance rentals required at the time of assignment of the lease to the Company. Advance rentals paid after assignment are charged to expense as carrying costs in the period incurred. Costs of oil and gas leases held for resale are valued at lower of cost or net realizable value and included in current assets since they could be sold within one year, although the holding period of individual leases may be in excess of one year. The cost of oil and gas leases sold is determined on a specific identification basis.

Inventory. Inventory consists primarily of tubular goods that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market value.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of $3,426,000 and $4,417,000,

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Notes to consolidated financial statements (Continued)

net of accumulated amortization of $3,563,000 and $1,083,000, as of December 31, 2007 and December 31, 2006, respectively.

On February 24, 2006, in conjunction with the Combination, the Company replaced its prior revolving credit facility with a new revolving credit facility. The remaining net deferred loan costs of $376,000 associated with the retired debt, were written off and included in *Interest expense* in 2006. In addition, on July 6, 2006, the Company entered into a term loan facility. The new deferred loan costs on these facilities are being amortized over the life of the loans, which mature February 24, 2010 and March 27, 2012, respectively.

On March 27, 2007, the Company amended its 1st lien revolving credit facility, repaid its existing 2nd lien term loan credit facility and entered into a new 2nd lien term loan credit facility. The Company paid an arrangement fee of $2.5 million at the date of closing of the new 2nd lien term loan credit facility. This fee is being amortized to *Interest expense* over the five-year term of the facility beginning in April 2007. The amendment of the 1st lien revolving credit facility on March 27, 2007 resulted in a $100 million, or 21 percent, reduction of the borrowing base on such facility. As such, the prorata portion of the remaining debt issuance costs associated with the 1st lien revolving credit facility, totaling approximately $766,000, were written off and included in *Interest expense* in the three months ended March 31, 2007. The remaining debt issuance costs of $433,000 associated with the existing 2nd lien term loan credit facility repaid in full on March 27, 2007 were written off and included in *Interest expense* during the three months ended March 31, 2007.

Future amortization expense as of December 31, 2007 for each of the years ended December 31, 2008, 2009, 2010, 2011 and 2012 is approximately $1,258,000, $1,280,000, $470,000, $331,000 and $87,000, respectively.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties under the provisions of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized acquisition costs relating to proved properties are depleted on a field basis using the unit-of-production method based on proved reserves. The depreciation of capitalized exploratory drilling and development costs is based on the unit-of-production method using proved developed reserves on a field basis.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion and depreciation. Generally, no gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base. Ordinary maintenance and repair costs are generally expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until such time as the related project is developed and proved reserves are established or impairment is determined. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. At December 31, 2007 and 2006 the Company had excluded $19.0 million and $5.4 million, respectively, of capitalized costs from depletion and had capitalized interest of $2,647,000 and $2,129,000, during 2007 and 2006, respectively.

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the Company reviews its long-lived assets to be held and used, including proved oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and gas properties by amortization base (field) or by individual well for those wells not constituting part of an amortization base. For each property

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. The Company recognized impairment expense of $7,267,000, $9,891,000 and $2,295,000 during the years ended December 31, 2007, 2006 and 2005, respectively, related to its proved oil and gas properties.

Unproved oil and gas properties are each periodically assessed for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. During the years ended December 31, 2007, 2006 and 2005, the Company recognized expense of $3,086,000, $196,000 and $199,000, respectively, related to abandoned prospects, which is included in *Exploration and abandonments* in the accompanying consolidated statements of operations.

Exploratory well costs. Costs of drilling exploratory wells are capitalized, pending management s determination of whether the wells have found proved reserves. If proved reserves are found, the costs remain capitalized. If proved reserves are not found, the capitalized costs of drilling the well are charged to expense. Management makes this determination as soon as possible after completion of drilling considering the guidance provided in SFAS No. 19 and FASB Staff Position (FSP) No. 19-1 Accounting for Suspended Well Costs.

SFAS No. 19 provides that such costs should not be carried as an asset for more than one year following completion of drilling unless the well has found oil and gas reserves in an area requiring a major capital expenditure before production could begin. In that case, the costs of such exploratory well would continue to be carried as an asset pending determination of whether proved reserves had been found only as long as the well had found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure was made and drilling of the additional exploratory wells was under way or firmly planned for the near future. If both those conditions were not met, the well costs were charged to expense.

The Company adopted the provisions of FSP No. 19-1 effective January 1, 2006. FSP 19-1 amends SFAS No. 19 to provide that in those situations where exploration drilling has been completed and oil and gas reserves have been found, but such reserves cannot be classified as proved when drilling is complete, the drilling costs may be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either of the criteria is not met, the well is assumed to be impaired and the costs charged to expense. Any well that has not found reserves is charged to expense. Management performs this evaluation on a quarterly basis. The adoption of FSP No. 19-1 had no impact on the Company s consolidated financial position or results of operations.

The following table provides an aging as of December 31, 2007 and 2006 of capitalized exploratory well costs based on the date the drilling was completed:

	December 31,	
	2007	2006
	(In thousands)	

Wells in progress	$ 4,199	$ 4,118
Capitalized exploratory well costs that have been capitalized for a period of one year or less	16,857	17,110
Capitalized exploratory well costs that have been capitalized for a period greater than one year		5,275
Total exploratory well costs	$ 21,056	$ 26,503

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Notes to consolidated financial statements (Continued)

During 2006 and 2007, the Company drilled four vertical exploration wells in the Western Delaware Basin of Texas. One of the four wells is currently flowing gas to sales. Below is a description of the status of the remaining three wells.

The first well drilled in the project area had been completed in two of the four prospective formations that are being tested in the project area and had found both zones capable of producing gas in the vertical well bores; however, quantities found were not commercial. The evaluation conducted on this well was to determine the viability of another one of the four prospective formations which is deeper than the formations to which the well had previously been completed. This formation is a shale formation which is present and productive in another of the Company s exploratory wells located in the Western Delaware Basin. The evaluation of this formation indicated that conditions were unfavorable for commercial success. This well was temporarily abandoned, and the Company expensed the costs associated with this well of approximately $7.6 million primarily in the third quarter of 2007. This expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the year ended December 31, 2007.

The second well drilled in the project area, reached total depth in September 2006 and was completed and flowing gas to sales during its initial evaluation stage. However, quantities of natural gas were not commercial. The evaluation of a deeper formation in this well bore indicated that conditions were unfavorable for commercial success. This well was temporarily abandoned, and the Company expensed the costs of approximately $6.5 million associated with this well in the fourth quarter of 2007. This expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the year ended December 31, 2007.

During 2007, a third well in the Western Delaware Basin was drilled to a shallower, previously untested, prospective formation. During June 2007, the Company determined that the well had not found sufficient reserves to justify its completion or its inclusion in the evaluation of the viability of any additional prospective formations in the project area. The well was temporarily abandoned, and the Company has recognized exploratory dry hole expense of approximately $2.9 million primarily in the second quarter of 2007. Such expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the year ended December 31, 2007.

The capitalized exploratory wells in progress and exploratory well costs of approximately $21.1 million have been deferred for a period of one year or less and are related primarily to the Company s New Mexico Shelf and New Mexico Basin properties.

The changes in capitalized exploratory well costs were as follows:

	Year Ended December 31, (In thousands)		
	2007	**2006**	**2005**
Beginning capitalized exploratory well costs	$ 26,503	$ 4,370	$ 2,149
Additions to exploratory well costs pending the determination of proved reserves	97,368	25,170	6,156

Reclassifications due to determination of proved reserves	(95,869)	(2,759)	(3,934)
Exploratory well costs charged to expense	(6,946)	(278)	(1)
Ending capitalized exploratory well costs	$ 21,056	$ 26,503	$ 4,370

Other property and equipment. Other capital assets include buildings, vehicles, computer equipment and software, telecommunications equipment and furniture and fixtures. These items are recorded at cost and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from 2 to 15 years.

Environmental. The Company is subject to extensive Federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may

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Notes to consolidated financial statements (Continued)

require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Management believes no liabilities of this nature existed at December 31, 2007 or 2006.

Oil and gas sales and imbalances. Oil and gas revenues are recorded at the time of delivery of such products to pipelines for the account of the purchaser or at the time of physical transfer of such products to the purchaser. The Company follows the sales method of accounting for oil and gas sales, recognizing revenues based on the Company s share of actual proceeds from the oil and gas sold to purchasers. Oil and gas imbalances are generated on properties for which two or more owners have the right to take production in-kind and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance.

At December 31, 2007, the Company had a gas imbalance liability, included in *Asset retirement obligations and other long-term liabilities* in the accompanying consolidated balance sheet of approximately $621,000 related to the Company s overtake position of 96,215 Mcf on certain wells and a gas imbalance receivable, included in *Other assets, net* in the accompanying consolidated balance sheet of approximately $367,000 related to the Company s undertake position of 81,569 Mcf on certain wells. The net undertake of 4,264 Mcf that arose in 2007, valued at approximately $14,000, was recorded net as a decrease to *Oil and gas production* expense in the accompanying consolidated statement of operations for the year ended December 31, 2007.

At December 31, 2006, the Company had a gas imbalance liability, included in *Asset retirement obligations and other long-term liabilities* in the accompanying consolidated balance sheet of approximately $539,000 related to the Company s overtake position of 85,348 Mcf on certain wells and a gas imbalance receivable, included in *Other assets, net* in the accompanying consolidated balance sheet of approximately $299,000 related to the Company s undertake position of 66,438 Mcf on certain wells. The net overtake of 12,837 Mcf that arose in 2006, valued at approximately $83,000, was recorded net as an increase to *Oil and gas production* expense in the accompanying consolidated statement of operations for the year ended December 31, 2006.

Derivative instruments and hedging. The Company applies the provisions of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. This statement requires the recognition of all derivative instruments as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists as permitted by FASB Interpretation (FIN) No. 39, Offsetting of Amounts Related to Certain Contracts .

Under the provisions of SFAS No. 133, the Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a fair value hedge) or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a cash flow hedge). Special accounting for qualifying hedges allows the effective portion of a derivative instrument s gains and losses to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate and assess the effectiveness of the transactions that receive hedge accounting treatment. Both at the inception of a hedge and on an ongoing basis, a hedge must be expected to be highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. If the Company determines that a derivative instrument is no longer

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

highly effective as a hedge, it discontinues hedge accounting prospectively and future changes in the fair value of the derivative are recognized in current earnings. The amount already reflected in *Accumulated other comprehensive (loss) income* remains there until the hedged item affects earnings or it is probable that the hedged item will not occur by the end of the originally specified time period or within two months thereafter. The Company assesses hedge effectiveness at the end of each quarter.

In accordance with SFAS No. 133, changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities or firm commitments, through earnings. Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in *Accumulated other comprehensive (loss) income* and reclassified into earnings in the period in which the hedged item affects earnings. Ineffective portions of a derivative instrument s change in fair value are immediately recognized in earnings. Derivative instruments that do not qualify, or cease to qualify, as hedges must be adjusted to fair value and the adjustments are recorded through net income (loss).

Asset retirement obligations. The Company accounts for the obligations in accordance with SFAS No. 143, Asset Retirement Obligations. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depreciation of the asset. Changes in the liability due to passage of time are recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and gas properties and records such reimbursements as reductions of *General and administrative expense*. Such fees totaled approximately $1,083,000, $799,000 and $591,000 for the years ended December 31, 2007, 2006 and 2005, respectively.

Stock-based compensation. The Company applies the provisions of SFAS No. 123R, Share Based Payment, to transactions in which the Company exchanges its equity instruments for employee services, and transactions in which the Company incurs liabilities that are based on the fair value of the Company s equity instruments or that may be settled by the issuance of those equity instruments in exchange for employee services. The cost of employee services received in exchange for equity instruments, including employee stock options, is measured based on the grant-date fair value of those instruments. That cost is recognized as compensation expense over the requisite service period (generally the vesting period). Generally, no compensation cost is recognized for equity instruments that do not vest.

Interest and other income. The Company collects rental income on its commercial building from lessees. Rental revenue is recognized on a straight-line basis over the term of the rental agreement.

As discussed more fully in Note G *Stockholders equity and stock issued subject to limited recourse notes*, the Company accrues interest income on notes receivable from employees.

Income taxes. The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, Accounting for Income Taxes. Under the asset and liability method of SFAS No. 109, 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. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. Under SFAS No. 109, the effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company adopted the provisions of FIN No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109, on January 1, 2007. FIN No. 48 clarifies the accounting for uncertainty

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109 and prescribes a recognition threshold and measurement process for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Based on its evaluation, the Company has concluded that there are no significant uncertain tax positions requiring recognition in its consolidated financial statements. The Company s evaluation was performed for the tax years ended December 31, 2006 and 2007, the tax years which remain subject to examination by major tax jurisdictions as of December 31, 2007.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2007 presentation. These reclassifications had no impact on net income (loss), total stockholders equity or cash flows.

Note C. Disclosures about fair value of financial instruments

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Notes receivable officers and employees. The carrying amounts approximate fair value due to the comparability of the interest rate to risk-adjusted rates for similar financial instruments.

Line of credit and term note. The carrying amount of borrowings outstanding under the Company s revolving credit facility and term note (see Note J *Long-term debt*) approximate fair value because the instruments bear interest at variable market rates.

Commodity price collars and price swaps. The fair value of commodity price collars and price swaps are estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Management s estimated fair value represents the estimated amounts that the Company would expect to receive or pay to settle the derivative contracts (see Note I *Derivative financial instruments*).

Note D. Business combination

On February 27, 2006, the Company closed a Combination Agreement with the Chase Group whereby ownership in certain oil and gas properties and non-producing leasehold acreage in Southeast New Mexico (the Chase Group Properties) were combined with the properties previously owned by CEHC. The results of the Chase Group Properties have been included in the consolidated financial statements since that date.

The Chase Group received cash in the aggregate amount of $409 million and 34,794,636 shares of Resources common stock valued at $384 million for an aggregate purchase price of $796 million including transaction costs. The value of the Resources common stock shares issued was determined based on an agreed upon fair market value of the assets purchased evaluated using reserve engineering estimates. This entire transaction was accounted for using the purchase method of accounting. At the time of the Combination, due to a difference in book and tax basis of the acquired properties, the Company recognized a deferred tax liability of approximately $227.3 million.

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Notes to consolidated financial statements (Continued)

The following table summarizes the final allocated net purchase price of the Combination, including capitalized transaction costs:

		(In thousands)
Proved oil and gas properties	$	830,096
Unproved oil and gas properties		200,000
Total assets acquired		1,030,096
Asset retirement obligations		(6,158)
Chase investors asset purchase obligation		(906)
Deferred tax liability		(227,291)
Total liabilities assumed		(234,355)
Net purchase price	$	795,741

As discussed in Note K *Commitments and contingencies*, the Company was obligated under the Combination Agreement to offer to purchase additional working interests in the Chase Group Properties from nine individuals within the Chase Group for total consideration of approximately $906,000. In April 2007, the Company satisfied this obligation by paying $256,000 in cash and issuing 54,230 shares of common stock. This aggregate purchase price is reflected in *Proved properties* and the related obligation is reflected in *Chase Group unaccredited investors asset purchase obligation* in the accompanying consolidated balance sheet as of December 31, 2006.

The following table represents pro forma consolidated statements of operations for the years ended December 31, 2006 and 2005 as though the Combination had been completed as of January 1, 2006 and January 1, 2005, respectively:

	Year Ended December 31,			
	2006		2005	
	(In thousands, except per share data)			
Pro forma (unaudited)				
Operating revenues	$	219,746	$	174,614
Net income	$	23,451	$	19,006
Net income applicable to common shareholders	$	23,451	$	19,006
Net income per common share:				
Basic	$	0.43	$	0.42

Diluted	$	0.41	$	0.42

On February 27, 2006, the Company signed a contract operator agreement with Mack Energy Corporation (MEC), an affiliate of the Chase Group, whereby the Company engaged MEC as contract operator to provide certain services with respect to the Chase Group Properties. This agreement was terminated and replaced with a Transition Services Agreement on April 23, 2007, which terminated upon completion of the Company s initial public offering on August 7, 2007. See further discussion in Note N *Related parties*.

Note E. New accounting pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company adopted SFAS No. 157 effective January 1, 2008, and it has had no material impact on the Company s consolidated financial statements.

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Notes to consolidated financial statements (Continued)

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, which will become effective in 2008. SFAS No. 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. The Company adopted this statement January 1, 2008, and the Company did not elect the fair value option for any of its eligible financial instruments or other items. As such, the adoption had no impact on the consolidated financial statements.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FIN No. 39-1). FIN No. 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FIN No. 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Adoption of FIN No. 39-1 is not expected to have a material impact on the Company s consolidated financial statements.

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The consensus in EITF Issue 06-11 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2007. Retrospective application of EITF Issue 06-11 is not permitted. Early adoption is permitted; however, the Company does not intend to adopt EITF Issue 06-11 prior to the required effective date of January 1, 2008. The Company does not expect the adoption of EITF Issue 06-11 to have a significant effect on its financial statements since the Company historically has accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), which replaces FASB Statement No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non- controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be the Company s fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations the Company consummates after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51. SFAS No. 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15,

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

2008, which will be the Company s fiscal year 2009. Based upon the December 31, 2007 balance sheet, the statement would have no impact.

Note F. Asset retirement obligations

The Company s asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The following table summarizes the Company s asset retirement obligation transactions recorded in accordance with the provisions of SFAS No. 143 during the years ended December 31, 2007 and 2006:

	Year Ended December 31,	
	2007	2006
	(In thousands)	
Asset retirement obligations at beginning of period	$ 8,700	$ 1,120
Liability incurred upon acquiring and drilling wells	471	7,443
Accretion expense	444	287
Liabilities settled upon plugging, abandoning or selling wells	(26)	
Revisions to estimated cash flows	(171)	(150)
Asset retirement obligations at end of period	$ 9,418	$ 8,700

Note G. Stockholders equity and stock issued subject to limited recourse notes

Equity commitments. Pursuant to a stock purchase agreement (the Stock Purchase Agreement) entered into on August 13, 2004, the Company obtained private equity commitments totaling $202.5 million, comprised of equity commitments from fourteen private investors (the Private Investors) of approximately $188.9 million and equity commitments from the five original officers (the Officers) of the Company in the aggregate amount of $13.6 million. The original commitments were subject to call by a vote of the board of directors over a four year period beginning August 13, 2004 (the Take-Down Period), with the first date on which capital was called being August 13, 2004. Subsequent calls were made on November 11, 2004, June 22, 2005, December 7, 2005 and February 10, 2006. The percentage of total commitments called per capital call date was approximately 15.0 percent, 23.3 percent, 10.0 percent, 15.0 percent and 22.0 percent, respectively. In conjunction with the exchange of CEHC common stock for Resources common stock as of the date of the Combination, the remaining 14.7 percent of these private equity commitments was terminated.

In addition to this arrangement between the Private Investors and the Officers, certain employees and executive officers of the Company entered into separate subscription agreements with the Company. The officers and employees equity purchases were paid in a combination of cash and the issuance of notes payable to the Company with recourse only to any equity security of the Company held by the respective officer or employee (the Purchase Notes). Based on guidance contained in SFAS No. 123R, the agreements to sell stock to the Officers and certain employees subject to Purchase Notes are accounted for as the issuance of options (Bundled Capital Options for the Officers and Capital Options for certain employees) on the dates that the various subscription agreements were signed and the purchase commitments were made.

Capital calls. From inception of the Company through February 23, 2006, the Private Investors purchased 16,113,170 Preferred Units for $161.1 million in cash. The Officers had purchased 2,240,083 CEHC common shares and 938,303 Preferred Units for $3.6 million in cash and Purchase Notes totaling $8.0 million. Certain employees purchased 425,221 Preferred Units for $1.0 million in cash and Purchase Notes totaling $3.8 million.

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Notes to consolidated financial statements (Continued)

6% Series A preferred stock. Preferred stock dividends were generally paid on the anniversary of date of issue. Preferred stock dividends of approximately $132,000 and $2,567,000 were paid during the years ended December 31, 2007 and 2006, respectively. As discussed in Note A *Organization and nature of operations* and below, the majority of the CEHC preferred stock was converted into Resources common stock on the Combination date. Final dividend payments on converted CEHC 6% Series A Preferred Stock were made in March 2006.

Dividend payments continued to be made to the eighteen employee shareholders that did not convert their shares of CEHC preferred stock to Resources common stock through April 16, 2007. On April 16, 2007, these CEHC preferred shares were exchanged for 190,972 shares of the Company s common stock. These shares are reported as if converted on the Combination date. Final dividend payments on this final portion of converted CEHC 6% Series A Preferred Stock were made on April 16, 2007.

Purchase Notes. On April 23, 2007, the executive officers repaid their Purchase Notes in full, including principal of $9,426,000 and accrued interest of $1,037,000. The agreements to sell stock to the executive officers of the Company subject to Purchase Notes were accounted for as the issuance of options. As such, the repayment of the executive officer Purchase Notes represents the full exercise of the options on the Bundled Capital Options the Officers held as well as the Capital Options of one certain employee who is currently an executive officer.

At December 31, 2007, the Company had Purchase Notes receivable from certain employees of approximately $330,000 comprised of an aggregate principal amounts of $288,000 and accrued interest of $42,000.

At December 31, 2006, the Company had Purchase Notes receivable from the Officers and certain employees of approximately $12,858,000 comprised of aggregate principal amounts of $11,803,000 and accrued interest of $1,055,000.

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Notes to consolidated financial statements (Continued)

Stock issuances treated as Capital Options. The following table summarizes the Bundled Capital Options activity for the years ended December 31, 2007, 2006 and 2005:

	Number of Bundled Capital Options	Weighted Average Exercise Price
Year ended December 31, 2005		
Outstanding at beginning of period	1,100,000	$ 9.52
Bundled Capital Options granted		$
Cancelled/forfeited		$
Outstanding at end of period	1,100,000	$ 9.52
Vested outstanding at end of period	696,303	$ 9.52
Year ended December 31, 2006		
Outstanding at beginning of period	1,100,000	$ 9.52
Bundled Capital Options granted		$
Cancelled/forfeited	(161,697)	$ 9.52
Outstanding at end of period	938,303	$ 9.52
Vested outstanding at end of period	938,303	$ 9.52
Year ended December 31, 2007		
Outstanding at beginning of period	938,303	$ 9.52
Bundled Capital Options granted		$
Bundled Capital Options exercised	(938,303)	$ 9.52
Cancelled/forfeited		$
Outstanding at end of period		$
Vested outstanding at end of period		$

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Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

The following table summarizes the Capital Options activity for the years ended December 31, 2007, 2006 and 2005:

	Number of Capital Options	Weighted Average Exercise Price
Year ended December 31, 2005		
Outstanding at beginning of period	85,000	$ 8.40
$10 Capital Options granted	277,500	$ 9.05
$15 Capital Options granted	120,000	$ 12.28
Cancelled/forfeited		$
Outstanding at end of period	482,500	$ 9.74
Vested outstanding at end of period	305,422	$ 9.74
Year ended December 31, 2006		
Outstanding at beginning of period	482,500	$ 9.74
$15 Capital Options granted	16,000	$ 12.13
Cancelled/forfeited	(73,279)	$ 9.81
Outstanding at end of period	425,221	$ 9.81
Vested outstanding at end of period	425,221	$ 9.81
Year ended December 31, 2007		
Outstanding at beginning of period	425,221	$ 9.81
$10 Capital Options exercised	(270,828)	$ 8.97
$15 Capital Options exercised	(116,008)	$ 12.26
Cancelled/forfeited		$
Outstanding at end of period	38,385	$ 8.34
Vested outstanding at end of period	38,385	$ 8.34

The following table summarizes information about the Company s vested Capital Options outstanding and exercisable at December 31, 2007 and 2006:

	Capital Options Outstanding,	Weighted Average Remaining	Weighted Average

		Vested and Exercisable	Contractual Life	Exercise Price	Intrinsic Value
Vested Capital Options Outstanding and Exercisable					
As of December 31, 2007					
Exercise price	$ 10.00	38,385	2.52 years	$ 8.34	$ 562,000
As of December 31, 2006					
Exercise price	$ 10.00	309,213	3.61 years	$ 8.90	$ 3,268,000
Exercise price	$ 15.00	116,008	3.83 years	$ 12.26	$ 633,000
		425,221		$ 9.81	$ 3,901,000

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Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

The following table summarizes the stock-based compensation for all Capital Options and is included in *General and administrative expense* in the accompanying consolidated statement of operations for the years ended December 31, 2007, 2006 and 2005:

	2007	Year Ended December 31, 2006	2005
Stock-based compensation expense from Capital Options:	$	$ 975,000	$ 1,746,000
Bundled Capital Options			
Stock-based compensation expense	$	$ 508,000	$ 578,000
Options vesting during period		242,000	275,004
Weighted average grant date fair value per option	$	$ 2.10	$ 2.10
Capital Options			
Stock-based compensation expense	$	$ 467,000	$ 1,168,000
Options vesting during period		119,799	272,867
Weighted average grant date fair value per option	$	$ 3.90	$ 4.28

Conversion of CEHC 6% Series A Preferred Stock and CEHC common stock. On February 27, 2006, concurrent with the closing of the Combination described in Note A *Organization and nature of operations* and Note D *Business combination*, the majority of the shares of CEHC preferred stock and shares of CEHC common stock outstanding were converted to shares of Resources common stock, as described below.

Eighteen employee shareholders owning an aggregate of 254,621 shares of CEHC preferred stock and 127,313 shares of CEHC common stock did not convert their shares to Resources common stock at the date of the Combination. On April 16, 2007, these remaining shares of CEHC were exchanged for 318,285 shares of the Company s common stock. These shares are reported as if converted on the Combination date. In addition, CEHC made a final dividend payment to these eighteen employee shareholders on their CEHC preferred stock in the aggregate amount of approximately $99,000 on April 16, 2007.

Also in conjunction with the Combination described in Note A *Organization and nature of operations* and Note D *Business combination* and the conversion of CEHC preferred stock into Resources common stock at the ratio of 0.75:1, the CEHC Bundled Capital Options were converted into Resources Bundled Capital Options and CEHC Capital Options were converted into Resources Capital Options. The Resources Capital Options are considered to be exercisable for 1.25 shares of Resources common stock.

Common stock held in escrow. On February 27, 2006 the Company entered into an agreement with certain stockholders of the Company in which certain of the Company s shareholders placed 430,755 shares of Resources common stock in an escrow account (the Escrow Agreement). The Escrow Agreement provided that if, on or before February 27, 2007 (the Initial Period), the Company consummated one of two specified transactions, the shares held in escrow would be released to the Company for reissuance to Messrs. Leach, Beal, Copeland, Kamradt and Wright. Neither of those specified transactions occurred in the Initial Period. However, the Escrow Agreement specified that if neither of the two specified transactions occurred during the Initial Period, a sale of the Company in a business combination on or before August 26, 2007 where the per share valuation of the Company s common stock in such sale was equal to or greater than $28.00 per share would result in the release of the shares held in escrow to the Company for reissuance to Messrs. Leach, Beal, Copeland, Kamradt and Wright. These conditions for release of these shares to Messrs. Leach, Beal, Copeland, Kamradt and Wright were not met by August 26, 2007, and thereafter the escrow agent distributed the escrowed shares to the original owners of the shares. These shares have been treated as issued and outstanding in the accompanying consolidated financial statements since issuance in February 2006 and through December 31, 2007.

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

Note H. Stock incentive plan

The Company s 2006 Stock Incentive Plan (together with applicable option agreements and restricted stock agreements, the Plan) provides for granting stock options and restricted stock awards to employees and individuals associated with the Company.

Restricted stock awards. Under the Plan, the Company has issued 431,549 restricted shares, net of forfeitures. Restrictions have lapsed with respect to 60,000 shares as of December 31, 2007.

On June 1, 2006, as part of the Company s director compensation plan, the compensation committee of the Company s board of directors approved the issuance of restricted stock to the Company s eight non-executive directors. Under the Plan, the Company issued 40,000 shares of common stock, subject to certain restrictions as set forth in the Plan and a restricted stock agreement between the Company and such director. These restrictions lapsed with respect to 100 percent of the restricted shares on January 2, 2007. The grant date fair value of the stock was estimated by the Company to be approximately $616,000, which the Company recognized as stock-based compensation expense over seven months beginning June 2007.

On June 28, 2006, the Company issued 155,764 shares of common stock to certain non-officer employees, subject to certain restrictions as set forth in the Plan. Provided that the employee has been continuously employed by the Company from the date of grant through the lapse date, the restrictions will lapse with respect to 100 percent of the restricted shares on the earlier of (i) the third annual anniversary of the date of grant, (ii) the date upon which a change of control, as defined in the Plan, occurs, or (iii) the date upon which the employee s employment with the Company is terminated by reason of death, disability or involuntary termination, as defined in the Plan. The grant date fair value of the stock was estimated by the Company to be approximately $2,399,000, which the Company will recognize as stock-based compensation expense over three years beginning July 2006. During the third and fourth quarters of 2006, as defined in the Plan, the Company issued 16,340 and 1,480 additional shares, respectively, of common stock to new employees, subject to the same restrictions described above. The grant date fair value of the stock was estimated by the Company to be approximately $274,000, which the Company will recognize as stock-based compensation expense over three years from the date of grant.

On April 23, 2007, the Company issued a total of 20,000 shares of restricted common stock comprised of 2,500 shares to each of the eight non-executive directors subject to certain restrictions as set forth in the Plan. These restrictions lapsed with respect to 100 percent of the restricted shares on April 23, 2007, the date of grant. The grant date fair value of the stock was estimated to be approximately $340,000 which the Company recognized as stock-based compensation expense in April 2007.

In August 2007, the Company s board of directors appointed a new non-executive director who was granted 5,000 shares of restricted common stock by the compensation committee of the Company s board of directors in accordance with the Company s director compensation plan, subject to certain restrictions as set forth in the Plan and a restricted stock agreement between the Company and such director. These restrictions lapse with respect to 100 percent of the restricted shares twelve months from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $64,000, which the Company will recognize as stock-based compensation expense over twelve months beginning August 2007.

In September and November 2007, the compensation committee of the Company s board of directors approved grants of 112,753 shares in the aggregate of restricted common stock to the non-officer employees of the Company, subject to certain restrictions as set forth in the Plan and respective restricted stock agreements between the Company and each such employee. These restrictions lapse with respect to 100 percent of the restricted shares three years from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $1,633,000 which the Company will recognize as stock-based compensation expense over the next three years beginning September 2007.

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

On November 8, 2007, the compensation committee of the Company s board of directors authorized and approved amendments to certain outstanding agreements related to options to purchase the Company s common stock that were previously awarded to certain of the Company s executive officers and employees in order to amend such award agreements so that the subject stock option award would constitute deferred compensation that is compliant with Section 409A of the Internal Revenue Code of 1986, as amended (the Code), or exempt from the application of Code Section 409A.

On November 16, 2007, the Company s named executive officers signed an Amendment to Nonstatutory Stock Option Agreement. These amendments modify the subject stock options in accordance with the proposed modifications listed below. The modifications to certain stock option awards issued prior to the combination transaction was to establish mandatory exercise dates beginning in 2008 and continuing through 2011. Regarding the modifications to the June 2006 options, the subject strike price was reset to $15.40 per share from the original strike price of $12.00 per share. To compensate for the $3.40 increase in the strike price, the Company s named executive officers were granted 83,242 shares in the aggregate of restricted stock on November 19, 2007 based on a share price of $18.38. The share price used to determine the number of restricted shares granted was the mean of the high and the low trading prices on the New York Stock Exchange on the date of grant, as required by the Plan. The lapse of forfeiture restrictions of this restricted stock is in 25% increments on the lapse dates of January 1, 2008; June 12, 2008; June 12, 2009; and June 12, 2010 or upon the occurrence of certain specified events. See *Stock option modifications* below for a more expanded discussion.

All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior the lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company s restricted stock awards for the years ended December 31, 2007 and 2006 is presented below:

	Number of Common Shares	**Grant Date Fair Value**
Restricted stock:		
Outstanding at January 1, 2006		
Shares granted	213,584	$ 3,289,000
Shares cancelled/forteited	(1,368)	
Lapse of restrictions		
Outstanding at December 31, 2006	212,216	
Shares granted	220,995	$ 2,037,000
Shares cancelled/forteited	(1,662)	
Lapse of restrictions	(60,000)	
Outstanding at December 31, 2007	371,549	

The Company recorded stock-based compensation for restricted stock of $1,378,000 and $1,044,000, which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations, for the years ended December 31, 2007 and 2006, respectively. Future stock-based compensation expense related to restricted stock outstanding at December 31, 2007 for the years ending December 31, 2008, 2009 and 2010 is expected to be approximately $1,464,000, $993,000 and $404,000, respectively. The income tax benefit recognized in the accompanying statement of operations for restricted stock was approximately $533,000 and $407,000 for the years ended December 30, 2007 and 2006, respectively.

Stock option awards. The stock options granted from August 13, 2004 through February 23, 2006 under the Stock Option Plan were to purchase Preferred Units. A portion of the options vested based upon passage of time (Time Vesting) and a portion of the options vested based upon the Company obtaining certain results related to a liquidation value (Performance Vesting). Seventy-eight percent of the aggregate options granted were vested

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

based on Time Vesting, in which they vested one-third each year for a three year period, which would result in approximately 61 percent, 28 percent and 11 percent of their total grant date fair value being expensed in the first, second and third years, respectively, commencing on the first anniversary of the date of grant. The remaining 22 percent of the aggregate options granted were vested based on Performance Vesting. Performance Vesting was considered to be achieved when the Company attained a liquidation valuation which resulted in a 25 percent internal rate of return and a return on investment of two times the total dollars invested by the original shareholders of the Company, upon the occurrence of one of the following events:

(i) the liquidation, dissolution or winding up of the affairs of the Company,

(ii) a sale of all or substantially all of the assets of the Company and a distribution to the shareholders of the proceeds of such sale, or

(iii) any merger, consolidation or other transaction resulting in at least 50 percent of the voting securities of the Company being owned by a single person or a group.

As a result of the Combination, event (iii) listed above occurred, which resulted in a change of control as defined in the Stock Option Plan. As such, the 78 percent of the aggregate options which vested based on Time Vesting were immediately vested as of the date of the Combination. CEHC s board of directors determined that, based upon the value received by the CEHC shareholders in the Combination, the thresholds for internal rate of return and return on investment which determined the portion of vesting based on Performance Vesting, were not met and that 22 percent portion of the options were not vested.

The CEHC board of directors determined that CEHC would vest the 22 percent of aggregate stock options based on Performance Vesting for only the stock option holders who were non-officers, if CEHC s officers agreed that the 22 percent of aggregate stock options based on Performance Vesting for the officers would vest at the end of three years after the closing of the Combination, which will result in approximately 33 percent, 33 percent and 34 percent of their total grant date fair value being expensed in the first, second, and third years, respectively, commencing on the first anniversary of the date of grant; each officer so agreed.

A summary of CEHC s stock option activity, under the Stock Option Plan, for year ended December 31, 2005 and the period ended February 27, 2006 (Combination date) is presented below. The amounts shown are immediately prior to the conversion of CEHC stock options to Resources stock options as a result of the Combination:

	January 1, 2006 through February 27, 2006		**Year Ended December 31, 2005**	
	Number of Units(a)	**Weighted Average Price**	**Number of Units(a)**	**Weighted Average Price**
Outstanding at beginning of period	1,365,075	$ 10.32	724,257	$ 10.00
Options granted	514,267	$ 10.68	665,247	$ 10.66
Options forfeited		$	(24,429)	$ 10.00

Options exercised		$			$	
Outstanding at end of period	1,879,342	$	10.42	1,365,075	$	10.32
Exercisable at end of period	1,562,770	$	10.51	182,033	$	10.00

(a) Each option Unit can be exercised for on Preferred Unit which is comprised of one-half of a share of CEHC common stock and one share of CEHC preferred stock.

Also in conjunction with the Combination described in Note A *Organization and nature of operations* and Note D *Acquisitions and business combinations* and the conversion of CEHC preferred stock into Resources common stock at the ratio of 0.75:1, the CEHC unit options were converted into Resources stock options. Each

Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

CEHC unit option, (considered to be exchangeable for one share of CEHC preferred stock and one-half of a share of CEHC common stock), was converted into 1.25 options to purchase common stock of Resources. Each Resources stock option is considered to be exchangeable for one share of Resources common stock. The following table summarizes the conversion of the CEHC unit options in conjunction with the Combination:

CEHC Unit Option Exercise Price	CEHC Unit Options	Conversion Rate	Resources Option Exercise Price	Resources Options
$10.00	1,721,010	1.25:1	$ 8.00	2,151,129
$15.00	158,332	1.25:1	$ 12.00	197,984
Total	1,879,342		Total	2,349,113

Under the Plan, effective June 12, 2006, the compensation committee of the Company s board of directors approved the issuance of 450,000 stock options in the aggregate to the current officers of the Company, which is comprised of the CEHC Officers and one certain employee. These options have an exercise price of $12, a contractual term of 10 years from the date of grant, and vest using a four year graded vesting schedule which will result in approximately 52 percent, 27 percent, 15 percent and 6 percent of their total grant date fair value being expensed in the first, second, third and fourth years, respectively, commencing on the first anniversary of the date of grant. In November 2007, these stock options were modified in order to comply with Section 409A of the Internal Revenue Code. See discussion below in *Stock option modifications*.

On August 15, 2007, the Company s board of directors approved the issuance of 200,000 stock options to a newly appointed officer of the Company and 15,000 stock options to a non-officer employee of the Company under the Plan. These options have an exercise price of $12.85, a contractual term of 10 years from the date of grant, and vest using a four year graded vesting schedule.

In calculating the compensation expense for these options, the Company has estimated the fair value of each grant using the Black-Scholes option-pricing model.

Stock option modifications. On November 8, 2007, the compensation committee of the Company s board of directors authorized and approved amendments to certain outstanding agreements related to options to purchase the Company s common stock that were previously awarded to certain of the Company s executive officers and employees in order to amend such award agreements so that the subject stock option award would constitute deferred compensation that is compliant with Section 409A of the Internal Revenue Code of 1986, as amended (the Code), or exempt from the application of Code Section 409A. As the offer to amend outstanding stock option agreements previously issued to certain of the Company s employees may constitute a tender offer under the Securities Exchange Act of 1934, on November 8, 2007, the board of directors of the Company authorized commencement of a tender offer to amend the applicable outstanding stock option award agreements in the form approved by the compensation committee.

Generally, the amendments provide that the employee stock options, which had previously vested in connection with the Combination, will become exercisable in 25% increments over a four year period beginning in 2008 and continuing through 2011 or upon the occurrence of certain specified events. Employee who decided to amend their stock option award agreement received a cash payment equal to $0.50 for each share of common stock subject to the amendment on January 2, 2008. The Company made aggregate cash payments of approximately $192,000 to such employees. The Company s affected executive officers received and accepted a similar offer to amend their stock option awards issued prior to the Combination on substantially the same terms, except such officers were not offered the $0.50 per share payment.

In addition, the Company s named executive officers received stock option awards in June 2006 to purchase 450,000 shares of common stock, in the aggregate, at a purchase price of $12.00 per share. The Company subsequently determined that the fair market value of a share of common stock as of the date of the award was

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Notes to consolidated financial statements (Continued)

$15.40. As a result, the compensation committee of the Company s board of directors authorized and approved an amendment to these stock option award agreements pursuant to which the exercise price of such stock options would be increased from $12.00 per share to $15.40 per share. The Company agreed to issue to the executive officer an award of the number of shares of restricted stock equal to (i) the product of $3.40 and the number of shares of common stock subject to the stock option award, divided by (ii) the Fair Market Value of a share of common stock on the date of the award of restricted stock.

The Company has determined that its aggregate compensation expense resulting from these proposed modifications of approximately $0.8 million will be recorded during the period from November 8 to December 31, 2007 and during the years ending December 31, 2008, 2009, and 2010.

A summary of the Company s stock option activity under the Plan, for the year ended December 31, 2007 and for the period from February 27, 2006 through December 31, 2006 is presented below. The amounts shown below are on a post-combination and post-conversion basis:

	Year Ended December 31, 2007		February 27, 2006 through December 31, 2006	
	Number of Options(a)	Weighted Average Price	Number of Options(a)	Weighted Average Price
Outstanding at beginning of period	2,797,997	$ 8.93	2,349,113	$ 8.34
Options granted	215,000	$ 12.85	450,000	$ 12.00
Options forfeited	(1,275)	$ 8.00	(1,116)	$ 10.88
Options exercised		$		$
Outstanding at end of period	3,011,722	$ 9.71	2,797,997	$ 8.93
Vested at end of period	2,063,499	$ 8.79	1,952,274	$ 8.40
Exercisable at end of period	508,462	$ 10.58	1,952,274	$ 8.40

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Concho Resources Inc. and subsidiaries

Notes to consolidated financial statements (Continued)

The following table summarizes information about the Company s vested stock options outstanding and exercisable at December 31, 2007 and 2006:

		Number Vested and Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value
Vested Options					
December 31, 2007					
Exercise price	$ 8.00	1,753,819	3.15 years	$ 8.00	$ 22,116,000
Exercise price	$ 12.00	197,180	5.72 years	$ 12.00	1,698,000
Exercise price	$ 15.40	112,500	8.45 years	$ 15.40	586,000
		2,063,499		$ 8.79	$ 24,400,000
Exercisable Options					
December 31, 2007					
Exercise price	$ 8.00	275,685	6.62 years	$ 8.00	$ 3,476,000
Exercise price	$ 12.00	120,277	7.78 years	$ 12.00	1,036,000
Exercise price	$ 15.40	112,500	8.45 years	$ 15.40	586,000
		508,462		$ 10.58	$ 5,098,000
Vested and Exercisable Options					
December 31, 2006					
Exercise price	$ 8.00	1,755,094	8.47 years	$ 8.00	$ 15,099,000
Exercise price	$ 12.00	197,180	8.86 years	$ 12.00	$ 769,000
		1,952,274		$ 8.40	$ 15,868,000

As discussed in Note B *Summary of significant accounting policies*, effective January 1, 2005, the Company adopted SFAS No. 123R using the modified retrospective basis to account for its stock-based compensation plans. The following table summarizes information about stock-based compensation for options which is

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Notes to consolidated financial statements (Continued)

recognized in *General and administrative expense* in the accompanying consolidated statement of operations for the years ended December 31, 2007, 2006 and 2005:

	Year Ended December 31, 2007	2006	2005
Grant date fair value and change in fair value due to option modification:			
Time Vesting options(a)	$ 87,000	$ 1,931,000	$ 2,891,000
Performance Vesting options:			
Officers(b)		500,000	606,000
Certain employee(b)		31,000	91,000
Non-officers(c)		142,000	278,000
Current officer stock options(d)	1,921,000	3,555,000	
Total	$ 2,008,000	$ 6,159,000	$ 3,866,000
Stock-based compensation expense from stock options:			
Time Vesting options(a)	$ 17,000	$ 5,085,000	$ 1,506,000
Performance Vesting options:			
Officers(b)	561,000	477,000	
Certain employee(b)	41,000	34,000	
Non-officers(c)		505,000	
Current officer stock options(d)	1,844,000	1,024,000	
Total	$ 2,463,000	$ 7,125,000	$ 1,506,000

(a) Options granted prior to February 27, 2006, vested immediately as of the date of the Combination, as a result of a change of control. Options granted thereafter vest using a four year graded vesting schedule by approval from the Board of Directors.

(b) Options granted prior to February 27, 2006, vest using a three year cliff vesting schedule by approval from CEHC s Board of Directors.

(c) Vested as of the date of the Combination by approval from CEHC s Board of Directors.

(d) Vest using a four year graded vesting schedule by approval from the Board of Directors. The 2007 grant date fair value includes an adjustment of $765,000 from a change in fair value due to the section 409A option modification.

Future stock-based compensation expense related to incentive stock options outstanding at December 31, 2007 for the years ended December 31, 2008, 2009 and 2010 is approximately $2,199,000, $849,000, $274,000 and $48,000 respectively. Future stock-based compensation expense related to incentive stock options outstanding at December 31, 2006 for the years ended December 31, 2007, 2008, 2009 and 2010 is approximately $1,962,000, $1,322,000, $443,000, and $99,000 respectively.

Income tax benefit recognized in the income statement for these stock-based compensation arrangements was $953,000, $2,779,000 and $528,000 for the years ended December 31, 2007, 2006 and 2005, respectively. No amounts have been treated as deductions to the Company s current taxable income for the years ended December 31, 2007, 2006 and 2005, since no options have been exercised. In calculating the compensation expense for options, the Company has estimated the fair value of each grant using the Black-Scholes option-pricing model. Assumptions

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Notes to consolidated financial statements (Continued)

utilized in the model are shown below. Amounts shown are assumptions under the Plan for options exercisable for Resources common stock at a rate of 1:1:

	2007	**2006**	**2005**
Risk-free interest rate	4.47%	4.81%	4.12%
Expected term (years)	6.25	2.87	2.89
Expected volatility	37.33%	37.12%	34.87%
Expected dividend yield	0.00%	0.00%	0.00%

Note I. Derivative financial instruments

Cash flow hedges. The Company, from time to time, uses derivative financial instruments as cash flow hedges of its commodity price risks. Commodity hedges are used to (a) reduce the effect of the volatility of price changes on the natural gas and crude oil the Company produces and sells and (b) support the Company s annual capital budgeting and expenditure plans.

Through December 31, 2006, the Company had entered into certain natural gas and crude oil zero cost price collars and crude oil price swaps to hedge a portion of its estimated natural gas and crude oil production for calendar years 2006, 2007 and 2008. On February 8, 2007, the Company entered into one natural gas price swap to hedge an additional portion of its estimated natural gas production for the period of March through December 2007. The Company designated all of these derivative instruments as cash flow hedges.

As of June 30, 2007, the Company determined that all of its natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133 for the reason stated in the following paragraph. These contracts are referred to as dedesignated hedges.

A key requirement for designation of derivative instruments as cash flow hedges is that at both at inception of the hedge and on an ongoing basis, the hedging relationship is expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Generally, the hedging relationship can be considered to be highly effective if there is a high degree of historical correlation between the hedging instrument and the forecasted transaction. In prior quarters, prices received for the Company s natural gas have been highly correlated with the Inside FERC El Paso Permian Basin spot price index at the first of each month (the Index) the Index referenced in all of the Company s natural gas derivative instruments. However, during the quarter ended September 30, 2007, this historical relationship did not meet the criteria as being highly correlated. Natural gas produced from the Company s New Mexico Shelf assets has a substantial component of natural gas liquids. Prices received for natural gas liquids are not highly correlated to the price of natural gas, but are more closely correlated to the price of oil. During the third quarter of 2007, the price of oil and natural gas liquids, and therefore, the prices the Company received for its natural gas (including natural gas liquids) rose substantially and at a significantly higher rate than the corresponding change in the Index. This has resulted in a decrease in correlation between the prices received and the Index below the level required for cash flow hedge accounting. According to SFAS No. 133, an entity shall discontinue prospectively hedge accounting for an existing hedge if the hedge is no longer highly effective. Hedge accounting must be discontinued regardless of whether the Company believes the hedge will be prospectively highly effective. The hedge must be discontinued during the period the hedges became ineffective. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges*. Because the gas and liquids prices fluctuate at different rates over time, the loss of effectiveness does not relate to any single date.

Therefore, June 30, 2007, is considered the last date the Company s natural gas hedges were highly effective, and the Company discontinued hedge accounting during all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges are recorded each period to *(Gain) loss on derivatives not designated as hedges*. Effective portions of dedesignated hedges, previously recorded in *Accumulated other comprehensive income*

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Notes to consolidated financial statements (Continued)

(*AOCI*) as of June 30, 2007, will remain in *AOCI* and be reclassified into earnings under *Natural gas revenues*, during the periods which the hedged forecasted transaction affects earnings.

Derivatives not designated as cash flow hedges. On September 20, 2007, the Company entered into four crude oil price swaps to hedge an additional portion of its estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,000 Bbls per day each with various fixed prices. The Company has not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments are recorded each period to *(Gain) loss on derivatives not designated as hedges.*

The following table sets forth the Company s outstanding crude oil and natural gas zero cost price collars and price swaps at December 31, 2007:

	Fair Market Value Asset/(Liability) (In thousands)	Aggregate Remaining Volume	Daily Volume	Index Price	Contract Period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(23,942)	951,600	2,600	$67.50(a)	1/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	1,866	4,941,000	13,500	$6.50 - $9.35(b)	1/1/08 - 12/31/08
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(12,472)	732,000	2,000	$75.78(a)(c)	1/1/08 - 12/31/08
Price swap	(10,517)	730,000	2,000	$72.84(a)(c)	1/1/09 - 12/31/09
Net liability	$ (45,065)				

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

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The Company s reported oil and gas revenue and average oil and gas prices includes the effects of oil quality and Btu content, gathering and transportation costs, gas processing and shrinkage, and the net effect of the commodity hedges. The following table summarizes the gains and losses reported in earnings related to the commodity financial instruments and the net change in *AOCI:*

	Year Ended December 31,		
	2007	2006	2005
		(In thousands)	
Increase (decrease) in oil and gas revenue from derivative activity:			
Cash (payments) receipts on cash flow hedges in oil sales	$ (11,091)	$ (7,000)	$ 1,150
Cash receipts from cash flow hedges in gas sales	188	1,232	472
Dedesignated cash flow hedges reclassed from AOCI in gas sales	1,103		
Total increase (decrease) in oil and gas revenue from derivative activity	$ (9,800)	$ (5,768)	$ 1,622
Gain (loss) on derivatives not designated as cash flow hedges:			
Mark-to-market	$ (22,089)	$	$ (1,966)
Cash receipts (payments) on derivatives not designated as cash flow hedges	1,815		(3,035)
Total gain (loss) on derivatives not designated as cash flow hedges	$ (20,274)	$	$ (5,001)
Gain (loss) from ineffective portion of cash flow hedges	$ (821)	$ 1,193	$ (1,148)
Accumulated other comprehensive income (loss):			
Cash flow hedges:			
Mark-to-market of cash flow hedges gain (loss)	$ (33,783)	$ 11,936	$ (18,697)
Reclassification adjustment for (gains) losses included in net income	10,903	5,768	1,622
Net AOCI upon dedesignation at June 30, 2007	(407)		
Net change, before taxes	(23,287)	17,704	(17,075)
Tax effect	9,102	(6,230)	5,982
Net change, net of tax	$ (14,185)	$ 11,474	$ (11,093)
Dedesignated cash flow hedges:			
Net AOCI upon dedesignation at June 30, 2007	$ 407	$	$
Reclassification adjustment for (gains) losses included in net income	(1,103)		
Total net change in AOCI (loss), net of tax	(696)		

Tax effect		272				
Net change, net of tax	$	(424)	$		$	

All of the Company s derivatives are expected to settle by January 8, 2010. Based on futures prices as of December 31, 2007, the Company expects a pre-tax loss of $22,606,000 to be reclassified into earnings and pre-tax loss of $696,000 to be reclassified out of *AOCI* into earnings during the twelve months ended December 31, 2008 related to the cash flow hedges and the dedesignated cash flow hedges, respectively.

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Note J. Long-term debt

The Company s long-term debt consists of the following:

	December 31, 2007	December 31, 2006
	(In thousands)	
Bank debt:		
1st Lien Credit Facility	$ 216,000	$ 455,700
2nd Lien Credit Facility		39,400
New 2nd Lien Credit Facility	109,900	
Unamortized original issue discount on New 2nd Lien Credit Facility	(496)	
Total long-term debt	$ 325,404	$ 495,100
Current portion of the 2nd and New 2nd Lien Credit Facility	2,000	400
Total debt	$ 327,404	$ 495,500

1st Lien Credit Facility. On February 24, 2006, in conjunction with the Combination, the Company replaced its prior revolving credit facility and its prior term loan facility with a new revolving credit facility, as described below. A portion of the initial advance from the new revolving credit facility was used to repay all funds borrowed under the prior revolving and term credit facilities. Remaining unamortized fees paid in connection with the issuance of the prior revolving and term credit facilities were fully expensed into *Interest expense* in the accompanying consolidated statement of operations for the year ended December 31, 2006 when the prior revolving and term credit facilities were replaced.

As of February 24, 2006, the Company entered into a credit agreement with a syndicate of banks (the 1st Lien Banks) which provides for a revolving credit facility (the 1st Lien Credit Facility) with commitments from the 1st Lien Banks aggregating $475 million, subject to a borrowing base. The borrowing base is calculated based on the Company s oil and gas reserves. The maturity date of the 1st Lien Credit Facility is February 24, 2010. The Company may also request the issuance of letters of credit up to $20 million. The borrowing commitment is reduced by any outstanding letters of credit. The initial advance on the 1st Lien Credit Facility made on February 27, 2006 was $421 million. The proceeds from this initial advance were used as follows:

	(In thousands)
Cash payment to the Chase Group in the Combination	$ 400,000
Repay balance on prior revolving credit facility	15,900
Bank fees and legal costs	5,100

Total	$	421,000

The initial borrowing base was $475 million. The borrowing base components are redetermined semiannually as of January 1 and June 30 of each year. In addition to the regular redetermination dates listed above, the 1st Lien Credit Facility required a special redetermination as of April 30, 2006. This special redetermination was conducted during the quarter ended June 30, 2006 by the 1st Lien Banks and both the borrowing base and the conforming borrowing base were affirmed at their current amounts. In addition to the scheduled redeterminations, the Company and the 1st Lien Banks are each provided the option to request an additional redetermination once between the scheduled redeterminations. The borrowing base remained at $475 million at December 31, 2006. The Company entered into the Second Amendment to the 1st Lien Credit Facility on March 27, 2007. The amendment allowed for the incurrence of additional indebtedness in the form of a $200 million second lien term loan. The amendment also redetermined the borrowing base at $375 million.

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Notes to consolidated financial statements (Continued)

Advances on the 1st Lien Credit Facility bear interest, at the Company s option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (7.25 percent and 8.25 percent at December 31, 2007 and 2006, respectively) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 100 - 225 basis points and 0 - 125 basis points, respectively, per annum depending on the balance outstanding. The Company pays commitment fees on the unused portion of the borrowing base ranging from 25 - 50 basis points per annum depending on the borrowing base available. The amount outstanding under this facility at December 31, 2006 was $455.7 million, of which $432 million was at the Eurodollar rate and $23.7 million was at the JPM Prime Rate. The Company used a portion of the net proceeds from its initial public offering that was completed in August 2007 to retire outstanding borrowings under the 1st Lien Credit Facility totaling $86.5 million. The amount outstanding under this facility at December 31, 2007 was $216.0 million, all of which was at the Eurodollar rate.

The 1st Lien Credit Facility also includes a same-day advance facility under which the Company may borrow funds on a daily basis from the 1st Lien Banks administrative agent. Advances made on this same-day basis cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin. There were no amounts outstanding on this facility at December 31, 2007 and 2006.

The Company s obligations under the 1st Lien Credit Facility are secured by substantially all of the Company s oil and gas properties. In addition, all but one of the Company s subsidiaries are guarantors, and all subsidiary general partners, limited partners and membership interests owned by the Company and its subsidiaries have been pledged as collateral in the credit agreement. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses no greater than 3.5 to 1.0, amended to 4.0 to 1.0 as of March 27, 2007, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be no less than 1.0 to 1.0, (b) limits on the incurrence of additional indebtedness and certain types of liens, (c) restrictions as to merger and sale or transfer of assets, and (d) a restriction from paying cash dividends. The Company was in compliance with all covenants of the 1st Lien Credit Facility at December 31, 2007 and 2006.

On July 6, 2006, the Company entered into the First Amendment to the 1st Lien Credit Facility. The Amendment allowed the Company to obtain additional financing in the form of a $40 million second lien term loan.

Borrowing base redetermination on 1st Lien Credit Facility. Regular redeterminations are scheduled under the Second Amendment to the 1st Lien Credit Facility on January 1 and June 30 of each year. In conjunction with the scheduled redetermination as of June 30, 2007 we requested an increase in the borrowing base in the amount of $50 million. Such request was approved by all the lenders and the borrowing base was redetermined at $425 million effective November 21, 2007.

2nd Lien Credit Facility. On July 6, 2006, the Company entered into an additional credit agreement arranged by Banc of America Securities LLC for a term loan facility in the amount of $40 million (the 2nd Lien Credit Facility). The full amount of this facility was funded on the closing date to reduce the amount outstanding under the 1st Lien Credit Facility by $32.1 million, with the remaining $7.9 million used for general corporate purposes.

The 2nd Lien Credit Facility provides a $40 million term loan, which bears interest, at the Company s option, based on (a) the prime rate of Bank of America, N.A. (BOA Prime Rate) (7.25 percent and 8.25 percent at December 31, 2007 and 2006, respectively) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar Rate advances and BOA Prime Rate advances vary, with interest margins of 400 basis points and 250 basis points, respectively. The Company may select interest periods on Eurodollar Rate advances of one, two, three, six, nine and twelve months, subject to availability. Interest is payable at the end of the selected interest period, but no less frequently than quarterly.

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Borrowings under the 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing our 1st Lien Credit Facility, which lien is subordinated to liens securing the 1st Lien Credit Facility. The 2nd Lien Credit Facility contains various restrictive covenants including (a) maintenance of certain financial ratios including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses of less than 4.5 to 1.0, (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be greater than 1.0 to 1.0 and (iii) maintenance of a ratio, as of January 1 and June 30 of each year, of the net present value of the Company s oil and gas properties to total debt to be greater than 1.5 to 1.0. (b) limits on the incurrence of additional indebtedness and certain types of liens, (c) restrictions as to merger and sale or transfer of assets, and (d) a restriction from paying cash dividends. The Company was in compliance with all covenants of the 2nd Lien Credit Facility at December 31, 2006.

The Company paid an arrangement fee of $500,000 at the date of closing of the 2nd Lien Credit Facility. This fee will be amortized over the five-year term of the facility beginning in July 2006.

The Company is required to repay $100,000 of the 2nd Lien Credit Facility on the last day of each calendar quarter beginning September 30, 2006. The maturity date of the 2nd Lien Credit Facility is July 5, 2011. The Company has the right to prepay the outstanding balance under the 2nd Lien Credit Facility at any time, provided, however, that the Company incurs a one percent prepayment penalty on any principal amount prepaid prior to July 5, 2007. The amount outstanding under this facility at December 31, 2006 was $39.8 million. The portion of this facility which is due within the next twelve months, $400,000, is reflected in *Current portion of long-term debt* in the accompanying consolidated balance sheet as of December 31, 2006. On March 27, 2007, the amount outstanding under 2nd Lien Credit Facility was repaid in full.

Refinancing of debt facilities. As of March 27, 2007, the Company amended its 1st Lien Credit Facility, repaid its 2nd Lien Credit Facility and entered into a new 2nd lien credit facility (the New 2nd Lien Credit Facility).

On March 27, 2007, the Company entered into the New 2nd Lien Credit Facility for a term loan facility in the amount of $200 million. The full amount of the facility was funded on the closing date. The New 2nd Lien Credit Facility was issued at a discount of 0.5 percent; thus, the Company received proceeds of $199.0 million. The proceeds from the borrowing were used to repay the 2nd Lien Credit Facility in full in the amount of $39.8 million without penalty, reduce the amount outstanding under the 1st Lien Credit Facility by $154.0 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes.

The amendment of the 1st Lien Credit Facility on March 27, 2007, resulted in a $100 million, or 21 percent, reduction of the borrowing base. As such, the pro rata portion of the remaining debt issuance costs associated with the 1st Lien Credit Facility, totaling approximately $766,000, was written off and included in *Interest expense* in the first quarter of 2007. The remaining debt issuance costs of $433,000 associated with the 2nd Lien Credit Facility repaid in full on March 27, 2007, were written off and included in *Interest expense* in the first quarter of 2007.

The Company paid an arrangement fee of $2.5 million at the date of closing. This fee is being amortized to *Interest expense* over the five-year term of the facility beginning in April 2007.

The New 2nd Lien Credit Facility provides a $200 million term loan, which bears interest, at the Company s option, based on (a) the Bank of America Prime Rate (7.25 percent at December 31, 2007) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and prime rate advances vary, with interest margins of 375 basis points and 225 basis points, respectively, until the sooner to occur of an initial public offering by the Company or the first anniversary of the closing date of the loan; thereafter, interest margins on Eurodollar rate advances and prime rate advances will be 425 basis points and 275 basis points, respectively. The Company may select interest periods on Eurodollar rate advances of one, two, three, six, nine and twelve months, subject to availability. Interest is payable at the end of the selected interest period, but no less frequently than quarterly.

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The Company is required to repay $0.5 million of the New 2nd Lien Credit Facility on the last day of each calendar quarter. These payments began on June 30, 2007. The maturity date of the New 2nd Lien Credit Facility is March 27, 2012. The Company has the right to prepay the outstanding balance under the New 2nd Lien Credit Facility at any time. The Company will not incur a prepayment penalty on any principal amount prepaid during the first twelve months of the loan. A two percent prepayment penalty will be incurred on any principal amount prepaid during the second year following the closing and one percent penalty will be incurred during the third year. After the third year, no prepayment penalty will be incurred.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing the 1st Lien Credit Facility. The second lien is subordinated to liens securing the 1st Lien Credit Facility. The New 2nd Lien Credit Facility contains various restrictive covenants including (a) maintenance of certain financial ratios including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other non-cash income and expenses of less than 4.5 to 1.0, (ii) maintenance of a ratio of current assets to current liabilities, excluding non-cash assets and liabilities related financial derivatives and asset retirement obligations, to be greater than 1.0 to 1.0 and (iii) maintenance of a ratio, as of January 1 and June 30 of each year, of the net present value of the Company s oil and gas properties to total debt to be greater than 1.5 to 1.0. (b) limits on the incurrence of additional indebtedness and certain types of liens, (c) restrictions as to merger and sale or transfer of assets, and (d) a restriction from paying cash dividends. The Company was in compliance with all covenants of the New 2nd Lien Credit Facility at December 31, 2007.

The amount outstanding under New 2nd Lien Credit Facility at December 31, 2007 was $111.9 million, net of a discount of $0.5 million, all of which was at the Eurodollar rate.

Repayment of a portion of New 2nd Lien Credit Facility. As mentioned in Note A *Organization and nature of operations*, IPO proceeds in the amount of $86.6 million were used to repay a portion of the New 2nd Lien Credit Facility on August 9, 2007. Subsequent to such repayment the outstanding balance, net of remaining original issue discount, as of August 9, 2007, was $112.4 million. As set forth by this facility s credit agreement, effective on the consummation of the IPO on August 9, 2007, the interest margins on Eurodollar rate advances and prime rate advances increased to 425 basis points and 275 basis points, respectively, and remain in effect at December 31, 2007.

A pro rata portion of the deferred loan costs associated with the New 2nd Lien Credit Facility were written off to interest expense in August 2007 in the amount of approximately $1.0 million. Additionally, a pro rata portion of the unamortized original issue discount related to the New 2nd Lien Credit Facility was written off to interest expense in August 2007 in the amount of approximately $0.4 million.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2007 for the years ended December 31, 2008, 2009, 2010, 2011, and 2012 are as follows:

	(In thousands)	
2008	$	2,000
2009		2,000

2010		218,000
2011		2,000
2012		103,900
Total	$	327,900

Note K. Commitments and contingencies

Operating leases. The Company is party to a non-cancelable operating lease for office space for its corporate headquarters in Midland, Texas through October 31, 2013.

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Notes to consolidated financial statements (Continued)

Future minimum lease commitments under the amended lease at December 31, 2007 are as follows:

	(In thousands)
2008	$ 497
2009	508
2010	519
2011	529
2012	538
2013 and thereafter	449
Total	$ 3,040

The Company recognizes expense on a straight-line basis in equal amounts over the lease term. Rent expense of $288,000, $685,000 and $316,000 for the years ended December 31, 2007, 2006 and 2005, respectively, is included in the accompanying consolidated statements of operations.

Daywork drilling contract commitments. The Company signed a daywork drilling contract with a drilling contractor on July 20, 2006, that provided the Company exclusive use of one rig with an operating day rate of $15,500 for a term that commenced on August 1, 2006 and ended on June 15, 2007. During February 2007, management decided to stack this rig due to budget modifications. The Company incurred contract drilling fees of approximately $1,296,000 related to this stacked rig during the year ended December 31, 2007. These costs were minimized as the drilling contractor secured work for the rig and refunded the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer.

The Company signed a new daywork drilling contract with the drilling contractor on June 26, 2007, that provides the Company exclusive use of one rig for a term that commenced on July 3, 2007 and ends on January 3, 2008. The Company may direct the rig to locations within the Permian Basin region as needed. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that the drilling contractor is liable for its employees, subcontractors and invitees. In addition, the drilling contractor is responsible for pollution or contamination from their equipment. The drilling contractor will release the Company of any liability for negligence of any party in connection with the drilling contractor. The operating day rate is $14,000. The operating day rate can be revised to reflect changes in costs incurred by the drilling contractor for labor and/or fuel. The contract allows an early termination by the Company with at least a thirty day notice and a payment of the lump sum termination amount equal to the current operating day rate less $6,000, multiplied by the days remaining through the end of the contract term. However, if the drilling contractor secures work for the subject rig with a new customer prior to the end of the contract term, drilling contractor will rebate the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer. Beginning on January 4, 2008, this contract was extended through July 31, 2008. The amended contract changed the operating day rate from $14,000 to $13,250.

The Company signed daywork drilling contracts with Silver Oak Drilling, LLC (Silver Oak), an affiliate of the Chase Group, on August 1, 2006, that provides the Company use of four drilling rigs for a term that commenced on August 1, 2006 and ended on July 31, 2007. The Company could direct the rig to locations located in New Mexico as needed. If the Company moved the rig out of certain New Mexico counties specified in the contract, all effective daywork rates will be increased by an additional $2,000 per day. The Company was solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak was liable for its employees, subcontractors and invitees. In addition, Silver Oak was responsible for pollution or contamination from their equipment. Silver Oak released the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate was $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate could be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s

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personnel needed. Under the contract, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contract, Silver Oak had a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they were released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company would then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company released the rigs, the Company, with 20 days notice, could withdraw its release and reactivate the contract for the remainder of the term to the extent the rig had not been committed to a third party in mitigation of the Company s damages. During February 2007, management decided to stack these four rigs due to budget modifications. The Company incurred contract drilling fees of approximately $2,973,000 related to this stacked rig during the year ended December 31, 2007, based on the drilling agreement described above. As of April 1, 2007, the Company began to utilize all four rigs, in order to proceed with its 2007 drilling budget.

The Company signed new daywork drilling contracts with Silver Oak on June 19, 2007, that provides the Company use of four drilling rigs for a term that commenced on August 1, 2007 and is in effect until drilling operations are completed on specified wells or for a term of 1 year. If any well commenced during the term of the contract is drilling at the expiration of the one year primary term, drilling will continue under the terms of the contract until drilling operations for that well have been completed. The Company may direct the rig to locations located in New Mexico as needed. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak is liable for its employees, subcontractors and invitees. In addition, Silver Oak is responsible for pollution or contamination from their equipment. Silver Oak will release the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate is $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate can be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s personnel needed. Under the contract, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contract, Silver Oak has a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they are released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company will then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company releases the rigs, the Company, with 20 days notice, may withdraw its release and reactivate the contract for the remainder of the term to the extent the rig has not been committed to a third party in mitigation of the Company s damages.

Oil & gas lease extension payment. The Company is party to an agreement which, in part, governs the exploration activities on the Company s acreage in the Western Delaware Basin shale play in Culberson County, Texas. The agreement contains a three-well drilling commitment. In addition to the drilling well requirement, the agreement required the Company to pay an additional $2.1 million ($150 per net acre for 13,952 net acres) in order to maintain its leasehold position, with such payment required within 90 days after the completion of the drilling of the third of the Company s three-well drilling commitment.

As of January 1, 2007, the Company had drilled or was drilling all three of these wells. The last of the three wells drilled reached total depth on January 19, 2007. On April 17, 2007, the Company made the payment of $2.1 million described above.

Chase Group accredited and unaccredited investors asset purchase obligation. As discussed in Note D *Business combination*, on February 27, 2006, as required by the Combination Agreement, the Company agreed to purchase working interests in the Chase Group Properties from certain individuals within the Chase Group. On May 18, 2006, the Company purchased interests in the Chase Group Properties from ten of such individuals within the Chase Group who were accredited investors in exchange for $8.9 million in cash and 111,323 shares of Resources common stock valued at $1.4 million for an aggregate purchase price of $10.3 million. The value of the common shares issued was $12 per share, as required by the Combination Agreement. The aggregate purchase price

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Notes to consolidated financial statements (Continued)

is reflected in *Proved properties* in the accompanying consolidated balance sheet at December 31, 2006. This transaction is included in the aggregate purchase price disclosed in Note D *Business combination*.

The Company was further obligated to offer to purchase additional interests in the Chase Group Properties from nine individuals within the Chase Group. In April 2007, the Company satisfied this obligation by paying $256,000 in cash and issuing 54,230 shares of common stock. The aggregate purchase price is reflected in *Proved properties* and the related obligation is reflected in *Chase Group unaccredited investors asset purchase obligation* in the accompanying consolidated balance sheet at December 31, 2006. This transaction is included in the aggregate purchase price disclosed in Note D *Business combination*.

Note L. Income taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109. The Company and its subsidiaries file federal corporate income tax returns on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by United States federal and state taxing authorities. The Company made estimated tax payments of $2,050,000, $1,725,000 and $100,000 during the years ended December 31, 2007, 2006 and 2005, respectively. Of the $2,050,000 taxes paid during the year ended December 31, 2007, $1,650,000 related to 2007 and $400,000 related to 2006.

The Company s provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses. The effective income tax rate for the years ended December 31, 2007, 2006 and 2005 was 38.7%, 42.2% and 51.1%, respectively.

SFAS No. 109 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Management monitors Company-specific, oil and gas industry and worldwide economic factors and assesses the likelihood that the Company s net operating loss carryforwards (NOLs) and other deferred tax attributes in the United States, state, and local tax jurisdictions will be utilized prior to their expiration. As of December 31, 2007 and 2006, the Company had no valuation allowances related to its deferred tax assets.

The Company adopted the provisions of FIN No. 48 on January 1, 2007. At the time of adoption and as of December 31, 2007, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 through 2007 remain subject to examination by major tax jurisdictions.

The FASB issued FIN No. 48-1, Definition of *Settlement* in FASB Interpretation No. 48, to clarify when a tax position is effectively settled. This guidance is important in determining the proper timing for recognizing tax benefits and applying the new information relevant to the technical merits of a tax position obtained during a tax authority examination. The FSP provides criteria to determine whether a tax position is effectively settled after completion of a tax authority examination, even if the potential legal obligation remains under the statute of limitations. The Company does not expect the adoption of this pronouncement to have a significant effect on its financial statements.

The components of income tax expense (benefit) are as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Current income tax expense (benefit) federal and state	$ 2,303	$ 1,761	$ 65
Deferred income tax expense (benefit) federal and state	13,716	12,618	1,974
Income tax expense (benefit)	$ 16,019	$ 14,379	$ 2,039

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Notes to consolidated financial statements (Continued)

The reconciliation between the tax expense (benefit) computed by multiplying pretax income (loss) by the U.S. federal statutory rate and the reported amounts of income tax benefit is as follows:

	Year Ended December 31,		
	2007	2006	2005
	(In thousands)		
Income (loss) at U.S. federal statutory rate	$ 14,483	$ 11,916	$ 1,358
State income taxes (net of federal tax effect)	2,631	2,083	70
Stock-based compensation		380	611
Statutory depletion carryover	(613)		
Nondeductible expense & other	(482)		
Expense (benefit) for income taxes	$ 16,019	$ 14,379	$ 2,039

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

	December 31,		
	2007	2006	2005
	(In thousands)		
Deferred tax asset:			
Federal net operating loss	$	$	$ 3,192
Stock-based compensation	4,440	3,776	590
Financial instruments	17,612		6,365
Statutory depletion carryover	613		
Federal tax credit carryovers	1,195		
Other	564	301	95
Total deferred tax assets	24,424	4,077	10,242
Deferred tax liability:			
Oil and gas properties, principally due to differences in basis and depletion and the deduction of intangible drilling costs for tax purposes	(269,938)	(245,464)	(5,338)
Financial instruments		(283)	
Other	(54)		

Total deferred tax liabilities		(269,992)		(245,747)		(5,338)
Net deferred tax asset (liability)	$	(245,568)	$	(241,670)	$	4,904

As of December 31, 2007 and 2006, there were no remaining deferred tax assets for net operating losses as they were fully utilized in 2006.

Texas margins tax. On May 18, 2006, the Governor of Texas signed into law House Bill 3 (HB-3) which modifies the existing franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent rate. HB-3 has also expanded the definition of tax paying entities to include limited partnerships. HB-3 becomes effective for activities occurring on or after January 1, 2007. The portion of deferred tax expense attributable to the enactment of the Texas margin tax was $113,000 and $515,000 at December 31, 2007 and 2006, respectively.

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Notes to consolidated financial statements (Continued)

Note M. Major customers and derivative counterparties

Sales to major customers. The Company s share of oil and gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and gas production.

Navajo Refining Company, L.P. accounted for 60 percent, 52 percent and 38 percent of the oil and gas revenues of the Company during the periods ended December 31, 2007, 2006 and 2005, respectively. DCP Midstream LP, formerly Duke Energy Field Services, accounted for 23 percent, 17 percent and 8 percent of the oil and gas revenues of the Company during the periods ended December 31, 2007, 2006 and 2005, respectively.

At December 31, 2007, the Company had receivables from Navajo Refining Company, L.P. and DCP Midstream LP of $20.9 million and $6.6 million, respectively, which are reflected in *Accounts receivable Oil and gas* in the accompanying consolidated balance sheet.

At December 31, 2006, the Company had receivables from Navajo Refining Company, L.P. and DCP Midstream LP of $11.0 million and $8.6 million, respectively, which are reflected in *Accounts receivable Oil and gas* in the accompanying consolidated balance sheet.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. The Company s credit facility agreements require that the senior unsecured debt ratings of the Company s derivative counterparties be not less than either A- by Standard & Poor s Rating Group rating system or A3 by Moody s Investors Service, Inc. rating system. At December 31, 2007 and 2006, the counterparties with whom the Company had outstanding derivative contracts met or exceeded the required ratings. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, management believes the associated credit risk is mitigated by the Company s credit risk policies and procedures and by the credit rating requirements of the Company s credit facility agreements.

At December 31, 2007, the Company had $1.9 million of derivative receivables representing amounts due from counterparties.

At December 31, 2006, the Company had $6.9 million of derivative receivables representing amounts due from counterparties. Approximately $6 million of short-term derivative receivables and $0.9 million of long-term derivative receivables are reflected in *Derivative instruments* and *Other assets* in the accompanying consolidated balance sheet, respectively.

At December 31, 2007 and 2006, the Company had $46.9 million and $6.2 million derivative liabilities representing amounts owed to counterparties, respectively. The fair market value of the derivative instruments were a net liability of approximately $45.1 million and a net asset of approximately $725,000 at December 31, 2007 and 2006, respectively.

Note N. Related parties

Contract Operator Agreement. On February 27, 2006, the Company signed a contract operator agreement with MEC, an affiliate of the Chase Group, whereby the Company engaged MEC as contract operator to provide certain services with respect to the Chase Group Properties. The initial term of the contract operator agreement was 5 years commencing on March 1, 2006 and ending on February 28, 2011. The Company and MEC entered into a Transition Services Agreement on April 23, 2007, which terminated the contract operator agreement and under which MEC provided certain field level operating services on the Chase Group Properties.

Transition Services Agreement. On April 23, 2007, the Company entered into a Transition Services Agreement with MEC whereby it provided services to the properties in Southeast New Mexico that the Company acquired from Chase Oil and its affiliates in the Combination. The Transition Services Agreement replaced the prior contract operator agreement with MEC. Under the Transition Services Agreement, MEC provided field level

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Notes to consolidated financial statements (Continued)

services, including pumping, well service oversight and supervision and certain equipment for workover and recompletion services, at costs prevailing in the area of the subject properties, but not to exceed charges for comparable services by and among MEC and its affiliates. MEC performed substantially similar services on behalf of the Company under the prior contract operator agreement prior to its termination. The Transition Services Agreement terminated upon the earlier to occur of (i) February 28, 2011; (ii) the date on which the Company completes the initial sale of its shares of common stock to the public pursuant to a registration statement filed under the Securities Act of 1933, as amended; or (iii) a change of control, as defined, or sooner as otherwise provided in the agreement or mutually agreed upon by the parties. The Transition Services Agreement was terminated effective August 7, 2007 upon the Company s completion of its initial public offering. Accordingly, upon termination, the Company s employees along with third party contractors assumed the operation of the subject properties.

The Company incurred charges from MEC of approximately $18.2 million during 2007 for services rendered under the contract operator agreement and Transition Services Agreement through the termination dates of the respective agreements.

The Company incurred charges from MEC of approximately $10.3 million for the year ended December 31, 2006 for services rendered under the contract operator agreement.

At December 31, 2007 and 2006, the Company had outstanding invoices payable to MEC of approximately $0.4 million and $1.8 million, respectively, which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

Other related party transactions. The Company also has engaged in transactions with certain other affiliates of the Chase Group, including Silver Oak, an oilfield services company, a supply company, a drilling fluids supply company, a pipe and tubing supplier, a fixed base operator of aircraft services and a software company.

The Company incurred charges from these related party vendors of approximately $43.8 million and $32.4 million for the years ended December 31, 2007 and 2006, respectively, for services rendered.

At December 31, 2007 and 2006, the Company had outstanding invoices payable to the other related party vendors identified above of approximately $1.7 million and $1.8 million, respectively, which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheets.

Overriding royalty and royalty interests. Certain members of the Chase Group own overriding royalty interests in certain of the Chase Group Properties. The amount paid attributable to such interests was approximately $2.4 million and $1.2 million for the years ended December 31, 2007 and 2006, respectively. The Company owed royalty payments of approximately $315,000 to these members of the Chase Group at December 31, 2007.

Royalties are paid on certain properties located in Andrews County, Texas to a partnership of which one of the Company s directors is the General Partner, and who also owns a 3.5% partnership interest. The Company paid approximately $205,000 and $72,000 for the years ended December 31, 2007 and 2006, respectively. The Company owed this partnership royalty payments of approximately $29,000 at December 31, 2007. The Company also paid this entity $24,000 and $80,000 in lease bonuses during the years ended December 31, 2007 and 2006, respectively.

In April 2005, the Company acquired certain working interests in 46,861 gross (26,908 net) acres located in Culberson County, Texas from an entity partially owned by a person who became an executive officer of the Company immediately following such acquisition. In connection with this acquisition, such entity retained a 2% overriding royalty interest in the acquired properties, which overriding royalty interest is now owned equally by such officer and a non-officer employee of the Company. The amount attributable to such interest was approximately $3,000 during the year ended December 31, 2007. During the year ended December 31, 2006, no payments were made related to this overriding royalty interest.

Prospect participation. Subsequent to the closing of the Combination, the Company acquired working interests from Caza in certain lands in New Mexico in which Caza owns an interest.

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Notes to consolidated financial statements (Continued)

The Company paid Caza approximately $3,000 and $2,102,000 for the years ended December 31, 2007 and 2006 for these interests.

At December 31, 2007 and 2006, the Company had no outstanding invoices owed to Caza.

Note O. Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. The Company matches 100 percent of employee contributions, not to exceed 6 percent of the employee s annual salary. Company contributions to the plan for the years ended December 31, 2007, 2005 and 2006 were approximately $419,000, $321,000, and $203,000, respectively.

Note P. Net income (loss) per share

Basic income (loss) per share is computed by dividing net income (loss) applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period. As discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes*, agreements to sell stock to the Officers and certain employees subject to Purchase Notes are accounted for as options (Bundled Capital Options and Capital Options , respectively). As a result, Bundled Capital Options and Capital Options are excluded from the weighted average number of common shares treated as outstanding during each period until the Purchase Notes are paid in full, thus exercising the options.

The computation of diluted income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. These amounts include unexercised Bundled Capital Options, Capital Options, stock options (as issued under the Stock Option Plan of CEHC adopted in 2004 and the Plan of CRI adopted in 2006, both as described in Note H *Stock incentive plan*) and restricted stock. Potentially dilutive effects are calculated using the treasury stock method.

The CEHC 6% Series A Preferred Stock were entitled to receive an amount equal to its stated value ($9.00) plus any unpaid dividends upon occurrence of a liquidation event, as defined. In connection with the Combination on February 24, 2006, a liquidation event occurred. Instead of receiving the stated value, the holders of the CEHC 6% Series A Preferred Stock agreed to accept 0.75 shares of Resources common stock in exchange for each share of CEHC 6% Series A Preferred Stock. This was considered to be an induced conversion, as defined in the FASB Emerging Issues Task Force Topic D-42, The Effect on the Calculation of Earnings per Share for the Redemption or Induced Conversion of Preferred Stock. The excess of the carrying amount of the CEHC 6% Series A Preferred Stock over the fair value of the Resources common stock issued is required to be added to 2006 net income to arrive at 2006 net income applicable to common shareholders for the year ended December 31, 2006.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2007, 2006 and 2005:

Year Ended

	2007	December 31, 2006 (In thousands)	2005
Weighted average common shares outstanding			
Basic	64,316	47,287	4,059
Dilutive Bundled Capital Options	847	2,516	
Dilutive Capital Options	154	192	
Dilutive common stock options	901	714	
Dilutive restrictive stock	91	20	
Diluted	66,309	50,729	4,059

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Notes to consolidated financial statements (Continued)

Since the Company had net income (loss) applicable to common shareholders, the effects of all potentially dilutive securities including Bundled Capital Options, Capital Options, incentive stock options and unvested restricted stock were considered in the computation of diluted earnings per share. Because the exercise prices of certain incentive stock options were greater than the average market price of the common shares and would be anti-dilutive, incentive stock options to purchase 450,000 of common stock were outstanding but not included in the computations of diluted income per share from continuing operations for the year ended December 31, 2006.

Note Q. Subsequent events

Asset held for sale. Effective January 24, 2008, the Company sold a prospect located in Eddy County, New Mexico for cash in the amount of $960,000. This lease is classified in *Assets held for sale* at cost at December 31, 2007. The gain on the sale will be approximately $700,000 which will be recorded in the consolidated statement of operations during the three months ended March 31, 2008.

Derivative instruments. On March 3, 2008, the Company entered into two oil price swaps to hedge an additional portion of its estimated oil production for April 2008 through December 2009. On March 11, 2008, the Company entered into a natural gas commodity swap to hedge an additional portion of its estimated natural gas production for calendar 2009. The Company did not designate any of these derivative instruments as cash flow hedges.

Note R. Supplementary information

Capitalized costs

	Year Ended December 31, 2007	2006
	(In thousands)	
Oil and gas properties:		
Proved	$ 1,303,665	$ 1,131,555
Unproved	251,353	267,663
Less accumulated depletion	(167,109)	(84,098)
Net capitalized costs for oil and gas properties	$ 1,387,909	$ 1,315,120

Costs incurred for oil and gas producing activities

	2007	Year Ended December 31, 2006	2005
		(In thousands)	

Property acquisition costs:			
Proved	$	$ 824,382	$ 7,834
Unproved	7,293	220,295	14,694
Exploration	116,019	49,254	7,301
Development	64,209	123,722	38,727
Capitalized asset retirement obligations	300	7,293	141
Total costs incurred for oil and gas properties	$ 187,821	$ 1,224,946	$ 68,697

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Notes to consolidated financial statements (Continued)

Reserve quantity information (unaudited)

The estimates of proved oil and gas reserves, which are located primarily in the Permian Basin region of West Texas and Eastern New Mexico were prepared by the Company s engineers. These reserve estimates were reviewed and confirmed by Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. Reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements except that future production costs exclude overhead charges for Company operated properties.

The following table summarizes the prices utilized in the reserve estimates for 2007, 2006 and 2005. Commodity prices utilized for the reserve estimates were adjusted for location, grade and quality.

	2007	2006	2005
Prices utilized in the reserve estimates before adjustments:			
Year-end Plains Marketing, L.P. West Texas Intermediate posted oil price per Bbl	$ 92.50	$ 57.75	$ 61.04(a)
Year-end Henry Hub spot market gas price per MMBtu	$ 6.795	$ 5.635	$ 10.080

(a) Year-end West Texas Intermediate futures oil price per Bbl

Oil and gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

	2007		2006		2005	
	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Oil and Condensate (MBbls)	Natural Gas (MMcf)
			(In thousands)			
Total Proved Reserves						
Balance, January 1	44,322	200,818	9,658	49,530	6,553	35,464
Purchase of minerals-in-place	105	354	27,163	137,963	191	1,095
Sales of minerals-in-place	(1)					

New discoveries and extensions(1)	13,140	48,751	10,226	39,427	3,256	15,864
Revisions of previous estimates	(1,191)	(12,022)	(430)	(16,595)	257	511
Production from continuing operations	(3,014)	(12,064)	(2,295)	(9,507)	(599)	(3,404)
Balance, December 31	53,361	225,837	44,322	200,818	9,658	49,530
Proved Developed Reserves:						
January 1	23,443	112,423	6,502	34,160	4,536	24,366
December 31	27,617	128,872	23,443	112,423	6,502	34,160

(1) The 2007, 2006 and 2005 new discoveries and extensions included 57,607, 31,266 and 7,024 net MMcfe, respectively, related to additions from the Company s infill drilling activities.

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Standardized measure of discounted future net cash flows (unaudited)

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

	2007	2006	2005
		(In thousands)	
Oil and gas producing activities:			
Future cash inflows	$ 6,507,955	$ 3,560,326	$ 972,662
Future production costs	(1,517,415)	(995,335)	(289,938)
Future development and abandonment costs	(484,140)	(484,462)	(62,275)
Future income tax expense	(1,482,633)	(530,212)	(186,539)
Future net cash flows	3,023,767	1,550,317	433,910
10% annual discount factor	(1,591,993)	(839,968)	(210,148)
Standardized measure of discounted future cash flows	$ 1,431,774	$ 710,349	$ 223,762

Changes in standardized measure of discounted future net cash flows (unaudited)

	2007	2006	2005
		(In thousands)	
Oil and gas producing activities:			
Purchases of minerals-in-place	$ 4,054	$ 795,072	$ 7,612
Sales of minerals-in-place	(54)		
Extensions and discoveries	511,519	156,266	98,826
Net changes in prices and production costs	802,584	(109,264)	99,041

Oil and gas sales, net of production costs	(240,066)	(160,468)	(40,301)
Changes in future development costs	72,441	(6,085)	(1,649)
Revisions of previous quantity estimates	(82,299)	(51,147)	7,302
Accretion of discount	85,533	17,317	14,933
Changes in production rates, timing and other	26,034	(10,119)	(12,596)
Change in present value of future net revenues	1,179,746	631,572	173,168
Net change in present value of future income taxes	(458,321)	(144,985)	(83,706)
	721,425	486,587	89,462
Balance, beginning of year	710,349	223,762	134,300
Balance, end of year	$ 1,431,774	$ 710,349	$ 223,762

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Notes to consolidated financial statements (Continued)

Selected quarterly financial results (unaudited)

	Quarter			
	First	**Second**	**Third**	**Fourth**
	(In thousands, except per share data)			
Year ended December 31,2007:				
Total operating revenues	$ 60,346	$ 66,103	$ 69,098	$ 98,786
Total operating costs and expenses	$ 41,938	$ 46,324	$ 46,602	$ 83,532
Income from operations	$ 18,408	$ 19,779	$ 22,496	$ 15,254
Net income	$ 4,623	$ 5,925	$ 7,954	$ 6,858
Net income available to common stockholders	$ 4,589	$ 5,914	$ 7,954	$ 6,858
Net income per common share Basic	$ 0.08	$ 0.10	$ 0.12	$ 0.09
Net income per common share Diluted	$ 0.08	$ 0.10	$ 0.11	$ 0.09
Year ended December 31,2006:				
Total operating revenues	$ 25,652	$ 51,718	$ 58,275	$ 62,645
Total operating costs and expenses	$ 24,026	$ 31,598	$ 38,543	$ 40,695
Income from operations	$ 1,626	$ 20,120	$ 19,732	$ 21,950
Net income (loss)	$ (1,428)	$ 7,621	$ 6,530	$ 6,945
Net income available to common stockholders	$ 9,027	$ 7,589	$ 6,498	$ 6,911
Net income per common share Basic	$ 0.38	$ 0.14	$ 0.12	$ 0.13
Net income per common share Diluted	$ 0.35	$ 0.13	$ 0.11	$ 0.12