CONCHO RESOURCES INC
Form 10-K
February 27, 2009

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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, 2008**
	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 100 **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 þ No o

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. þ

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 þ	Accelerated filer o	Non-accelerated filer o (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 computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant s most recently completed second fiscal quarter:
$1,993,092,788

Number of shares of registrant s common stock outstanding as of February 19, 2009: 84,913,298

Documents Incorporated by Reference:

Portions of the registrant s definitive proxy statement for its 2009 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2008, are incorporated by reference into Part III of this report for the year ended December 31, 2008.

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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, as amended, (the Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended, (the Exchange Act) 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 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 report, the words could, believe, anticipate, intend, estimate, ex may, continue, predict, potential, project and similar expressions are intended to identify forward-looking statem although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and elsewhere in this 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 and financial strategy;
- the estimated quantities of crude oil and natural gas reserves;
- our use of industry technology;
- our realized crude oil and natural gas prices;
- the timing and amount of the future production of our crude oil and natural gas;
- the amount, nature and timing of our capital expenditures;
- the drilling of our wells;
- our competition and government regulations;
- the marketing of our crude oil and natural gas;
- our exploitation activities or property acquisitions;
- the costs of exploiting and developing our properties and conducting other operations;
- general economic and business conditions;
- our cash flow and anticipated liquidity;
- uncertainty regarding our future operating results;
- our plans, objectives, expectations and intentions contained in this report that are not historical; and
- our ability to integrate acquisitions.

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

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GLOSSARY OF TERMS

The following terms are used throughout this 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.
Boe	One barrel of crude oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or condensate.
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.
LIBOR	London Interbank Offered Rate, which is a market rate of interest.
MBbl	One thousand barrels of crude oil, condensate or natural gas liquids.
MBoe	One thousand Boe.
Mcf	One thousand cubic feet of natural gas.
MMBbl	One million barrels of crude oil, condensate or natural gas liquids.
MMBoe	One million Boe.

MMBtu	One million British thermal units.
MMcf	One million cubic feet of natural gas.
NYMEX	The New York Mercantile Exchange.
NYSE	The New York Stock Exchange.
Net acres	The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent 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 percent.
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.

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	(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 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.
SEC	The United States Securities and Exchange Commission.
Secondary recovery	The recovery of oil and gas through the injection of liquids or gases into the reservoir, supplementing its natural energy. Secondary

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	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 a 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.

PART I

Item 1. *Business*

General

Concho Resources Inc., a Delaware corporation (Concho, Company, we, us and our) is an independent oil and n gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties. Our core operations are focused in the Permian Basin of Southeastern New Mexico and West Texas. These core operating areas are complemented by our activities in our emerging 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. and a portion of the oil and natural gas properties and related assets owned by Chase Oil Corporation (Chase Oil) and certain of its affiliates. Concho Equity Holdings Corp. was formed in April 2004 and represented the third of three Permian Basin-focused companies that have been formed since 1997 by certain members of our current management team (the prior two companies were sold to large domestic independent oil and gas companies).

Henry Entities Acquisition

On July 31, 2008, we closed our acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (which we refer to collectively as the Henry Entities), together with certain additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. We paid approximately $584.1 million in net cash for the acquisition of the Henry Entities and the related acquisition of the along-side interests, which was funded with (i) borrowings under our credit facility and (ii) net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock. The oil and gas assets acquired in the acquisition of the Henry Entities and the along-side interests (which we refer to as the Henry Properties) contained approximately 30.1 MMBoe of net proved reserves at the acquisition date.

Chase Oil Transaction

On February 24, 2006, we entered into a combination agreement in which we agreed to purchase oil and gas properties owned by Chase Oil, Caza Energy LLC and other related 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 then received 34,683,315 shares of our common stock and approximately $400 million in cash. The oil and gas properties contributed to us by the Chase Group are referred to as the Chase Group Properties.

Business and Properties

Our core operations are focused in the Permian Basin of Southeastern New Mexico and West Texas. The Permian Basin is one of the most prolific producing oil and gas regions in the United States. It underlies an area of Southeastern 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 basin is characterized by long life, shallow decline reserves. At December 31, 2008, 97.9 percent of our total estimated net proved reserves were located in our core operating areas and consisted of approximately 62.9 percent crude oil and 37.1 percent natural gas. We refer to our core operating areas as (i) New Mexico Permian and (ii) Texas Permian. The Permian 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. Producing horizons in our core properties include (i) the Yeso in the New Mexico Permian, which is located at depths ranging from 3,800 feet to 7,500 feet and (ii) the Wolfberry in the Texas Permian, the term applied to the combined Wolfcamp and Spraberry horizons, which is located at depths ranging from 7,000 feet to

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10,500 feet. 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 and the Wolfberry play, that we believe will allow us to grow proved reserves and production. We also have significant acreage positions in active emerging plays in the Lower Abo horizontal play in Southeastern New Mexico and the Bakken/Three Forks play in North Dakota. We view an emerging play as an area where we can acquire large undeveloped acreage positions and apply horizontal drilling, advanced fracture stimulation and/or enhanced recovery technologies to achieve economic and repeatable production results.

In 2008, we drilled or participated in the drilling of 243 gross (157.2 net) wells, 86.8 percent of which were completed as producers, 0.4 percent of which were dry holes and 12.8 percent of which were awaiting completion at December 31, 2008. In addition, in 2008, we recompleted or participated in the recompletion of 242 gross (198.6 net) wells, 90.9 percent of which were productive, 2.1 percent of which were unsuccessful and 7 percent were still in progress at December 31, 2008. We increased our total estimated net proved reserves by approximately 53.4 MMBoe, taking into account the effects of negative price revisions (10.1 MMBoe) and acquisitions. We produced approximately 7.1 MMBoe of oil and natural gas during 2008. In addition, we increased our average net daily production from 15.6 MBoe during the first quarter of 2008 to 25.2 MBoe during the fourth quarter of 2008, including the impact of the acquisition of the Henry Properties.

Drilling Activities

The following table sets forth information with respect to wells drilled and completed during the periods indicated. The 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,					
	2008		**2007**		**2006**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells						
Productive	118.0	76.8	60.0	38.5	93.0	57.8
Dry					7.0	2.4
Exploratory wells						
Productive	93.0	63.2	55.0	48.0	37.0	25.4
Dry	1.0	1.0	2.0	1.2	3.0	0.8
Total wells						
Productive	211.0	140.0	115.0	86.5	130.0	83.2
Dry	1.0	1.0	2.0	1.2	10.0	3.2
Total	212.0	141.0	117.0	87.7	140.0	86.4

The following table sets forth information about our wells for which drilling was in progress or are pending completion at December 31, 2008, which are not included in the above table:

	Drilling In-progress		**Pending Completion**	
	Gross	**Net**	**Gross**	**Net**

Development wells	7.0	5.4	17.0	10.2
Exploratory wells	4.0	1.7	14.0	6.0
Total	11.0	7.1	31.0	16.2

Our Production, Prices and Expenses

The following table sets forth summary information concerning our production results, average sales prices and operating costs and expenses for the years ended December 31, 2008, 2007 and 2006. The actual historical data in this table excludes production from the (i) Chase Group Properties for periods prior to February 27, 2006 and (ii) Henry Properties for periods prior to August 1, 2008.

	Years Ended December 31,		
	2008	**2007**	**2006**
Net production volumes:			
Oil (MBbl)	4,586	3,014	2,295
Natural gas (MMcf)	14,968	12,064	9,507
Total (MBoe)	7,081	5,025	3,880
Average daily production volumes:			
Oil (Bbl)	12,530	8,258	6,288
Natural gas (Mcf)	40,896	33,052	26,047
Total (Boe)	19,347	13,767	10,630
Average prices:			
Oil, without hedges (Bbl)	$ 91.92	$ 68.58	$ 60.47
Oil, with hedges (Bbl)	$ 85.25	$ 64.90	$ 57.42
Natural gas, without hedges (Mcf)	$ 9.59	$ 8.08	$ 6.87
Natural gas, with hedges (Mcf)	$ 9.54	$ 8.18	$ 7.00
Total, without hedges (Boe)	$ 79.80	$ 60.54	$ 52.62
Total, with hedges (Boe)	$ 75.38	$ 58.56	$ 51.12
Operating costs and expenses per Boe:			
Oil and gas production	$ 6.70	$ 5.96	$ 5.69
Oil and gas production taxes	$ 6.18	$ 4.84	$ 4.06
General and administrative	$ 5.76	$ 5.01	$ 5.60
Depreciation, depletion and amortization	$ 17.50	$ 15.28	$ 15.65

Summary of Core Operating Areas and Emerging Plays

The following is a summary of information regarding our core operating areas and emerging plays that are further described below:

	Proved Reserves at December 31, 2008		2008 Average Daily Sales Volumes	December 31, 2008 Number of Net Producing	Percent of PV-10 Operated by
	MBoe	PV-10 (In millions)	(Boe)	Wells	Us

Core Operating Areas:					
New Mexico Permian	95,055	$ 1,242.8	14,664	1,020.5	94.6%
Texas Permian	39,392	378.0	4,008	395.5	93.4%
Emerging plays and other	2,828	42.4	675	13.7	47.1%
Total	137,275	$ 1,663.2	19,347	1,429.7	

Core Operating Areas

Our core operating areas are located in the Permian Basin region of Southeastern New Mexico and West Texas, the largest onshore oil and gas basin in the United States. We refer to our core operating areas as the (i) New Mexico Permian and (ii) Texas Permian. At December 31, 2008, our core operating areas had estimated net proved reserves of 134.4 MMBoe, which accounted for 97.9 percent of our total estimated net proved reserves and 97.4 percent of our PV-10. At December 31, 2008, we owned interests in 3,403 gross wells in our core operating areas, of which we operated 2,294 (gross). At December 31, 2008, in our core operating areas, we had identified 3,465 drilling locations, with proved undeveloped reserves attributed to 811 of such locations, and 2,118 recompletion opportunities, with proved reserves attributed to 916 of such opportunities.

New Mexico Permian. We acquired the majority of our properties in this area from the Chase Group. This area represents our most significant concentration of assets and, at December 31, 2008, our estimated proved reserves of 95.1 MMBoe in this area accounted for 69.2 percent of our total net proved reserves and 75.1 percent of our PV-10. During 2008, our average net daily production from this area was approximately 14.7 MBoe per day, representing 75.6 percent of our total production for that time period.

Within this area we target two distinct producing areas, which we refer to 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 Strawn, Atoka and Morrow formations, with producing depths generally ranging from 7,500 feet to 15,000 feet.

During 2008, we drilled or participated in the drilling of 142 (123.9 net) wells in this area, of which 132 (114.4 net) were completed as producers, none were unsuccessful and 10 (9.5 net) were awaiting completion at December 31, 2008. During 2008, we (i) continued our development of the Blinebry interval of the Yeso formation, the top of which is located approximately 400 feet below the top of the Paddock interval of the Yeso formation, (ii) began our evaluation of drilling on 10 acre spacing in the Blinebry interval and (iii) continued our evaluation of the use of larger fracture stimulation procedures in the completion of certain wells. In addition, we continued our pilot waterflood commenced in September 2007 injecting water into the Paddock interval.

At December 31, 2008, we had 153,425 gross (71,423 net) acres in this area. At December 31, 2008, on our properties in this area, we had identified 1,685 drilling locations, with proved undeveloped reserves attributed to 355 of such locations, and 1,908 recompletion opportunities, with proved reserves attributed to 720 of such opportunities. Of the drilling locations we identified 993 locations intended to evaluate both the Blinebry and the Paddock intervals, while 17 locations are intended to evaluate only the Blinebry interval, with proved undeveloped reserves attributed to 176 of such total drilling locations.

Texas Permian. We acquired the majority of our properties in this area in the Henry Properties acquisition. At December 31, 2008, our estimated proved reserves of 39.4 MMBoe in this area accounted for 28.7 percent of our total net proved reserves and 22.3 percent of our PV-10. During 2008, our average net daily production from this area was approximately 4.0 MBoe per day, representing 20.7 percent of our total production for that time period.

The primary objective in the Texas Permian area is the Wolfberry in the Midland Basin. Wolfberry is the term applied to the combined Spraberry and Wolfcamp target interval which is typically encountered at depths of 7,000 to 10,500 feet. The Wolfberry is comprised of a sequence of basinal, interbedded shales and carbonates. We also operate properties on the Central Basin Platform where the Grayburg, San Andres and Clearfork objectives are shallower, typically encountered at depths of 4,500 to 7,500 feet. The reservoirs in these formations are largely carbonates, limestones and dolomites.

At December 31, 2008, we had 241,508 gross (69,727 net) acres in this area. In addition, at December 31, 2008, we had identified 1,780 drilling locations, with proved undeveloped reserves attributed to 456 of such locations, and 210 recompletion opportunities, with proved reserves attributed to 196 of such opportunities.

During 2008, we drilled or participated in the drilling of 69 (24.9 net) wells in this area, of which 54 (20.1 net) were completed as producers, none were unsuccessful and 15 (4.8 net) wells were awaiting completion at December 31, 2008. In addition, during 2008, we commenced the recompletion of 26 wells, 25 of which were producing at December 31, 2008 and 1 of which was unsuccessful.

Emerging Plays

At December 31, 2008, we were actively involved in drilling or participating in drilling activities in two emerging plays, in which we held 68,337 gross (32,861 net) acres and 2.3 MMBoe of proved reserves.

Lower Abo horizontal play. The Lower Abo horizontal play is an oil play along the northwestern rim of the Delaware Basin in Lea, Eddy and Chaves Counties, New Mexico. This play is found at vertical depths ranging from 6,500 feet to 9,000 feet and is being exploited utilizing horizontal drilling techniques.

At December 31, 2008, we held interests in 25,535 gross (21,638 net) acres in this play. In 2008, we drilled or participated in the drilling of 11 wells in this play with 8 wells producing, 1 waiting on completion and 2 wells drilling at December 31, 2008. At December 31, 2008, we had 2.1 MMBoe of proved reserves in the play.

Bakken/Three Forks play. The Bakken/Three Forks play is in the Williston Basin in North Dakota, primarily in Mountrail and McKenzie Counties. This Mississippian/Devonian age horizon consists of siltstones encased within and below a highly organic oil-rich shale package. This horizon is found at vertical depths ranging from 9,000 feet to 11,000 feet and is being exploited utilizing horizontal drilling techniques.

At December 31, 2008, we held interests in 42,802 gross (11,223 net) acres in this play. In 2008, we participated in the drilling of 17 wells in this play with 14 wells producing, 2 waiting on completion and 1 well drilling at December 31, 2008. At December 31, 2008, we had 0.2 MMBoe of proved reserves in the play.

Other emerging plays. We also own interests in the following other emerging plays:

Central Basin Platform of West Texas, where we drilled one unsuccessful Woodford shale exploratory well in 2008;

Western Delaware Basin of West Texas, where we drilled four exploratory wells prior to 2008, targeting the Bone Springs, Atoka, Barnett and Woodford shales, of which three were unsuccessful and one was successful; and

Arkoma Basin in Arkansas, where, in 2008, we participated in the drilling of three exploratory wells targeting both the Hale and the Fayetteville shale, all of which were in various stages of completion and evaluation at December 31, 2008.

Because of the current commodity price environment, the minimal success from drilling in these three other emerging plays and other activity in or around these three other emerging plays, we are currently not actively pursuing further exploration activities on these three other emerging plays. We are evaluating our alternatives related to these three other emerging plays.

Marketing Arrangements

General. We market our crude oil and natural gas in accordance with standard energy practices utilizing certain of our employees and external 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 drilling 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. A significant portion of our crude oil is connected directly to pipelines via gathering facilities in the respective field locations throughout Southeastern New Mexico, while a significant portion of our production in West Texas is transported by truck. The oil is then delivered either to hub facilities located in Midland, Texas or Cushing, Oklahoma or to third party refineries located in Southeastern New Mexico and the Panhandle and Gulf Coast area of Texas, with the majority of our crude oil going to a refinery in Southeastern New Mexico. 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

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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. We consider all 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 sold at the lease 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 a percentage of 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 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 2008, revenues from oil and natural gas sales to Navajo Refining Company, L.P. and DCP Midstream, LP accounted for approximately 59 percent and approximately 18 percent, 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 caused significant price increases. The recent 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 timing or duration of any such shortages.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights. 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 cost-based, 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 permits a pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC approved index. On March 21, 2006, FERC issued a decision setting the index for the period July 1, 2006 through July 2011 at the Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent. 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 at posted tariff 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, and market participants are prohibited from engaging in market manipulation. 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 these 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.

In August, 2005, Congress enacted the Energy Policy Act of 2005 (EPAct 2005). Among other matters, EPAct 2005 amends the Natural Gas Act to make it unlawful for any entity , including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC s rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704. EPAct 2005 therefore reflects a significant expansion of the FERC s enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued rules (Order 704) requiring that any market participant, including a producer such as Concho, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected by these rules any differently than other producers of natural gas.

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. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (Competition Bill) and H.B. 1920 (LUG Bill). The Competition Bill gives the Railroad Commission of Texas (RRC) the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. 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 is subject.

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.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth s atmosphere. In response to such studies, the U.S. Congress is considering legislation to reduce emissions of greenhouse gases. President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations. This requirement could increase our operational and compliance costs and result in reduced demand for our products.

Also, as a result of the United States Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate 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 Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal 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. In July 2008, the EPA released an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court s decision in *Massachusetts*. In the notice, the EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal, regional or state

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restrictions on emissions of carbon dioxide or other greenhouse gases that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions, which could have a material adverse effect on our business and the 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, 2008. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2009. However, we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operation.

Our Employees

At December 31, 2008, we employed 245 persons, including 128 in operations, 33 in financial and accounting, 33 in land, 16 in geosciences, 17 in reservoir engineering and 18 in administration. Of these, 220 worked at our Midland, Texas headquarters, including Texas field operations, and 25 in our New Mexico 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 SEC under the Exchange Act. The public may read and copy any materials that we file with 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 us, 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.

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Item 1A. *Risk Factors*

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC, before investing in our shares. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our shares could decline and you could lose all or part of your investment.

Risks Related to Our Business

Crude oil and natural gas prices are volatile. A decline in crude 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 gas properties depend primarily upon the prices we receive for our crude oil and natural gas production and the prices prevailing from time to time for crude oil and natural gas. Crude 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 crude oil and natural gas are subject to a variety of factors, including:

- the level of consumer demand for crude oil and natural gas;
- the domestic and foreign supply of crude oil and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign crude oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain crude 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 gas producing regions, including the Middle East, Africa and South America;
- technological advances affecting energy consumption; and
- worldwide economic conditions.

Furthermore, crude oil and natural gas prices were particularly volatile in 2008. For example, the NYMEX crude oil prices in 2008 ranged from a high of $145.29 to a low of $33.87 per Bbl, and the NYMEX natural gas prices in 2008 ranged from a high of $13.58 to a low of $4.35 per MMBtu. Further demonstrating the volatility of crude oil and natural gas prices, the NYMEX crude oil prices and NYMEX natural gas prices reached lows of $33.98 per Bbl and $4.08 per MMBtu, respectively, during the period from January 1, 2009 to February 19, 2009.

Further declines in crude oil and natural gas prices would not only reduce our revenue, but could further reduce the amount of crude 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 gas industry continues to experience 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 adversely affect the value of our common stock.

Drilling for and producing crude 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 crude oil and natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable crude 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. 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 or less economic than forecasted. 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 crude oil and natural gas prices;
- surface access restrictions;
- loss of title or other title related issues;
- crude oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for crude oil and natural gas.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of crude oil and/or natural gas that cannot be measured in an exact manner. Estimates of economically recoverable crude oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the quality, quantity and interpretation of available relevant data;

the assumed effects of regulations by governmental agencies;

the quality, quantity and interpretation of available relevant data;

the assumed effects of regulations by governmental agencies;

assumptions concerning future commodity prices; and

assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of crude oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. For example, the estimated discounted future net cash flows from our proved reserves at December 31, 2008 were calculated using the West Texas Intermediate posted crude oil price of $41.00 per Bbl and the NYMEX natural gas price of $5.71 per MMBtu, adjusted for location and quality by field, while the actual future net cash flows also will be affected by other factors, including:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil and gas; and
- changes in governmental regulations or taxation.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. It requires the use of commodity prices, as well as operating and development costs, prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for crude oil and natural gas production because of seasonal price fluctuations or other varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and gas industry in general. Therefore, the estimates of discounted future net cash flows or Standardized Measure included herein should not be construed as accurate estimates of the current market value of our proved reserves. If oil prices were $1.00 per Bbl lower than the price we used, our PV-10 at December 31, 2008, would have decreased from $1,663 million to $1,622 million. If natural gas prices were $0.10 per Mcf lower than the price we used, our PV-10 at December 31, 2008, would have decreased from $1,663 million to $1,646 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.

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 crude oil and natural gas reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of crude oil and natural gas reserves. At December 31, 2008, total debt outstanding under our credit facility was $630.0 million, and $329.7 million was available to be borrowed. Expenditures for exploration and development of oil and gas properties are the primary use of our capital resources. We invested approximately $339.0 million in exploration and development activities in 2008, and anticipate we could invest up to approximately $500 million in 2009 for exploration and development activities, dependent on our cash flow, on our properties under our original capital budget.

We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our 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 our outstanding common stock. Additional borrowings under our 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 credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the facility, which consent may be withheld by the lenders under our credit facility 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 crude oil and natural gas we are able to produce from existing wells;
- the prices at which our crude 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 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 production, revenues and results of operations.

We may not be able to obtain funding at all, or obtain funding on acceptable terms, to meet our future capital needs because of the deterioration of the credit and capital markets.

Global financial markets and economic conditions have been, and will likely continue to be, disrupted and volatile. The debt and equity capital markets have become uncertain. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. Also, as a result of concern about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, our ability to obtain capital under our credit facility may be impaired because of the recent downturn in the financial market, including the issues surrounding the solvency of certain institutional lenders and the recent failure of several banks. Specifically, we may be unable to obtain adequate funding under our credit facility because:

- our lending counterparties may be unwilling or unable to meet their funding obligations;
- the borrowing base under our credit facility is redetermined at least twice a year and may decrease due to a decrease in crude oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, or for other reasons; or

if any lender is unable or unwilling to fund their respective portion of any advance under our credit facility, then the other lenders thereunder are not required to provide additional funding to make up the portion of the advance that the defaulting lender refused to fund.

Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2008, we had approximately $630 million of outstanding debt under our credit facility, and our borrowing base was $960 million. The borrowing base limitation under our credit facility is semi-annually redetermined based upon a number of factors, including commodity prices and reserve levels. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any twelve-month period. Upon a redetermination, our borrowing base could be substantially reduced, and in the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. We utilize cash flow from operations, bank borrowings and equity financings to fund our acquisition, exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

Our producing properties are located in the Permian Basin of Southeastern New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties in our core operating areas are geographically concentrated in the Permian Basin of Southeastern New Mexico and West Texas. At December 31, 2008, 97.4 percent of our PV-10 was attributable to properties located in our core operating areas. 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 wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2008, approximately (i) 52.0 percent of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and gas properties located in Southeastern New Mexico; and (ii) 15.1 percent of our proved reserves were attributable to the Wolfberry play in West Texas. This concentration of assets within a small number of producing horizons exposes us to additional 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 a field.

Future price declines could result in a reduction in the carrying value of our proved oil and gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our oil and gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and gas properties, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

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 crude 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 crude 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 crude 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 crude 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 counterparties.

Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. At December 31, 2008, the net unrealized gain on our commodity price risk management contracts was approximately $172.4 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 at December 31, 2008 would have resulted in a decrease in the net unrealized gain on our commodity price risk management contracts, as reflected on our balance sheet at December 31, 2008, of approximately $3.6 million. We may continue to incur significant unrealized gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

We have entered into interest rate derivative instruments that may subject us to loss of income.

We have entered into derivative instruments designed to limit the interest rate risk under our current credit facility or any credit facilities we may enter into in the future. These derivative instruments can involve the exchange of a portion of our floating rate interest obligations for fixed rate interest obligations or a cap on our exposure to floating interest rates to reduce our exposure to the volatility of interest rates. While we may enter into instruments limiting our exposure to higher market interest rates, we cannot assure you that any interest rate derivative instruments we implement will be effective; and furthermore, even if effective these instruments may not offer complete protection from the risk of higher interest rates.

All interest rate derivative instruments involve certain additional risks, such as:

- the counterparty may default on its contractual obligations to us;
- there may be issues with regard to the legal enforceability of such instruments;

the early repayment of one of our interest rate derivative instruments could lead to prepayment penalties; or

unanticipated and significant changes in interest rates may cause a significant loss of basis in the instrument and a change in current period expense.

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 or interest rates 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 crude oil and natural gas prices and interest rates.

Nonperformance by the counterparties to our derivative instruments and commodity purchase agreements could adversely affect our financial condition and results of operations.

We routinely enter into derivative instruments with a number of counterparties to reduce our exposure to changes in oil and natural gas prices and interest rates. Recently, a number of financial institutions similar to those that serve as counterparties to our derivative instruments have been adversely affected by the global credit crisis. If a counterparty to one of these derivative instruments cannot or will not perform under the contract, we will not realize the benefit of the derivative, which could adversely affect our financial condition and results of operations.

Additionally, substantially all of our accounts receivable result from oil and natural gas sales to third parties in the energy industry. Recent market conditions have resulted in downgrades to credit ratings of energy industry merchants and financial institutions, affecting the liquidity of several of our purchasers and counterparties. We extend credit to our purchasers based on each party s creditworthiness, but we generally have not required our purchasers to provide collateral support for their obligations to us and therefore have no assurances that our counterparties will have the ability to pay us. If a purchaser of our oil and natural gas production fails to meet its obligations under our commodity purchase agreement, our financial condition and results of operations could be adversely affected.

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.

We have 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. At December 31, 2008, we had identified 3,589 drilling locations with proved undeveloped reserves attributable to 823 of such locations, and 2,121 recompletion opportunities with proved undeveloped reserves attributed to 540 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 (i) our ability to timely drill wells on lands subject to complex development terms and circumstances; and (ii) the availability of capital, equipment, services and personnel, seasonal conditions, regulatory and third party approvals, crude oil and natural gas prices, and drilling and recompletion costs and results. Because of these uncertainties, we may never drill or recomplete the numerous potential opportunities we have identified or produce crude 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 production, revenues and results of operations.

Approximately 44.3 percent of our total estimated net proved reserves at December 31, 2008, were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2008, approximately 44.3 percent 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.

At December 31, 2008, approximately 6.7 percent 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 crude 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 crude oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude 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 successfully integrate acquired companies, and any inability to do so may disrupt our business and hinder our ability to grow.

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 credit facility imposes certain direct limitations on our ability to enter into mergers or combination transactions involving our company. Our credit facility also limits 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 credit facility, we will be required to seek the consent of our lenders in accordance with the requirements of the facility, which consent may be withheld by the lenders under our credit facility in their discretion. Furthermore, given the current situation in the credit markets, many lenders are reluctant to provide consents in any circumstances, including to allow accretive transactions.

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.

The acquisition of the Henry Entities could expose us to potentially significant liabilities.

In connection with the acquisition of the Henry Entities, we purchased all of the sellers interests in the Henry Entities, rather than individual assets; therefore, the Henry Entities retained their liabilities, subject to certain exclusions and limitations contained in the purchase agreement, including certain unknown and contingent liabilities. We performed limited due diligence in connection with the acquisition of the Henry Entities and attempted to verify the representations of the sellers and of the former management of the Henry Entities, but there may be threatened, contemplated, asserted or other claims against the Henry Entities related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially adversely affect our production, revenues and results of operations. In addition, although the sellers agreed to indemnify us on a limited basis against certain liabilities, these indemnification obligations will expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

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, including those owned by the Henry Entities. We expect that acquisitions will continue to contribute to our future growth. Successful acquisitions of oil and gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future crude oil and natural 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 sometimes unable to obtain contractual indemnification for preclosing liabilities, including environmental liabilities and often acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties.

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

We operate in a highly competitive environment for acquiring properties, marketing crude 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 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 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 crude oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

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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 gas industry can fluctuate significantly, often in correlation with crude oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe 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 crude oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover 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 crude oil or natural gas is present or may be produced economically. Drilling for crude 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 periodically evaluate our unproved oil and gas properties for impairment, and could be required to recognize noncash charges to earnings of future periods.

At December 31, 2008, we carried unproved property costs of $377.2 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price circumstances, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, we will recognize noncash charges to earnings of future periods.

We may incur substantial losses and be subject to substantial liability claims as a result of our crude 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 crude oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing crude oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of crude 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 us 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 production, revenues and results of operations.

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

Market conditions or the unavailability of satisfactory crude oil and natural gas processing or transportation arrangements may hinder our access to crude oil and natural gas markets or delay our production. The availability of a ready market for our crude oil and natural gas production depends on a number of factors, including the demand for and supply of crude oil and natural gas, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation 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, natural gas liquids or natural gas pipeline or gathering, transportation 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 crude 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. These and other costs could have a material adverse effect on our production, revenues and 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, crude oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our production, revenues and results of operations.

We may incur substantial costs to comply with, and demand for our products may be reduced by, climate change legislation and regulatory initiatives.

The United States Congress is considering legislation to reduce emissions of greenhouse gases and more than one-third of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. In addition, the EPA has announced possible future regulation of greenhouse gas emissions under the Clean Air Act. Depending on the nature of potential regulations and legislation, such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business or demand for the oil and natural gas we produce.

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 crude 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 production, revenues and results of operations could be adversely affected.

The loss of our chief executive 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 our chief executive officer, Timothy A. Leach, and other key employees who have extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and 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 our investments in such projects.

We inject water into formations on some of our properties to increase the production of crude 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, if any, 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 crude oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

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 credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. At December 31, 2008, our total debt was $630.0 million. Assuming our total debt outstanding at December 31, 2008 was held constant, if interest rates had been higher or lower by 1 percent per annum, our annual interest expense would have increased or decreased by approximately $6.3 million. At December 31, 2008, our total borrowing capacity under our credit facility was $960 million, of which $329.7 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 credit facility imposes restrictions on us that may affect our ability to successfully operate our business.

Our credit facility limits 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 credit facility requires 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 our credit facility.

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 crude oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenue. Crude 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 crude 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 restated certificate of incorporation, amended and restated 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 restated 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 restated certificate of incorporation, amended and restated 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 percent 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 credit facility restricts 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.

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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 solely our common stock. We may also issue securities convertible into our common stock. Any of these events may dilute your ownership interest in us 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***

There are no unresolved staff comments.

Item 2. ***Properties***

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 at December 31, 2008. 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. at December 31, 2008 ($41.00 per Bbl West Texas Intermediate posted oil price and $5.71 per MMBtu NYMEX natural gas price, adjusted for location and quality by field, were used in the computation of future net cash flows). The following table sets forth certain proved reserve information by region at December 31, 2008:

	Oil (MBbl)	Gas (MMcf)	Total (MBoe)	PV-10(a) (In millions)
Core Operating Areas:				
New Mexico Permian	56,322	232,399	95,055	$ 1,242.8
Texas Permian	28,319	66,439	39,392	378.0
Emerging plays and other	1,644	7,110	2,828	42.4
Total	86,285	305,948	137,275	$ 1,663.2
Present value of future income tax discounted at 10%				(464.2)
Standardized Measure				$ 1,199.0

(a) Non-GAAP Financial Measure and Reconciliation (unaudited) PV-10 is derived from the Standardized Measure which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized

Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure 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. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

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The following table sets forth our estimated net proved reserves by category at December 31, 2008:

	Oil (MBbl)	Gas (MMcf)	Total (MBoe)	Percent of Total	PV-10 (In millions)
Proved developed producing	41,317	162,419	68,387	49.8%	$ 1,072.1
Proved developed non-producing	5,344	16,705	8,128	5.9%	99.3
Proved undeveloped	39,624	126,824	60,760	44.3%	491.8
Total proved	86,285	305,948	137,275	100.0%	$ 1,663.2

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2008 (dollars in thousands):

Year Ended December 31,(a)	Future Production (MBoe)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
2009	1,957	$ 82,647	$ 9,552	$ 192,656	$ (119,561)
2010	3,767	158,303	19,204	143,366	(4,267)
2011	4,711	199,055	25,310	121,547	52,198
2012	4,882	205,521	27,841	86,991	90,689
2013	4,445	187,524	27,365	21,739	138,420
Thereafter	40,998	1,724,511	412,737	82,599	1,229,175
Total	60,760	$ 2,557,561	$ 522,009	$ 648,898	$ 1,386,654

(a) Beginning in 2010 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling from the preceding years beginning in 2009.

The following table sets forth the changes in our proved reserve volumes by region during the year ended December 31, 2008 (in MBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
Core Operating Areas:t					
New Mexico Permian	(5,352)	29,657	36		(6,470)

Texas Permian	(1,463)	5,037	30,138	(6,884)
Emerging Plays and Other	(266)	1,730		112
Total	(7,081)	36,424	30,174	(13,242)

Production. Production volumes of 7.1 MMBoe includes production from our acquisition of the Henry Properties since August 1, 2008.

Extensions and discoveries. Extensions and discoveries are primarily the result of extension drilling in the Yeso formation of Southeastern New Mexico and the Wolfberry formation in West Texas and exploratory drilling in certain of our emerging plays.

Purchases of minerals-in-place. Purchases of minerals-in-place are primarily attributable to the acquisition of the Henry Properties.

Sales of minerals-in-place. We had no significant sales of minerals-in-place during 2008.

Revisions of previous estimates. Revisions of previous estimates are comprised of 10.1 MMBoe of negative revisions resulting from commodity price declines and 3.1 MMBoe of negative revision resulting from technical and performance evaluations. The Company s proved reserves at December 31, 2008 were determined using year-

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end NYMEX equivalent prices of $41.00 per Bbl of oil and $5.71 per MMBtu of gas, compared to $92.50 per Bbl of oil and $6.80 per MMBtu of gas at December 31, 2007.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by region at December 31, 2008:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:						
New Mexico Permian	108,728	53,994	44,697	17,429	153,425	71,423
Texas Permian	192,264	50,060	49,244	19,667	241,508	69,727
Emerging plays and other(a)	20,218	8,230	196,931	94,345	217,149	102,575
Total	321,210	112,284	290,872	131,441	612,082	243,725

(a) The following table sets forth gross and net acreage at December 31, 2008 for each of our five emerging plays and our acreage categorized as Other included in Emerging plays and other:

	Total Acres	
	Gross	Net
Southeastern New Mexico	60,915	30,581
Williston Basin of North Dakota	42,802	11,223
Central Basin Platform	22,925	22,156
Western Delaware Basin	68,814	23,593
Arkoma Basin of Arkansas	16,744	14,225
Total emerging plays	212,200	101,778
Other	4,949	797
Total emerging plays and other	217,149	102,575

The following table sets forth the expiration amounts of our gross and net undeveloped acreage at December 31, 2008 by region. Expirations may be less or reduced if production is established and/or continuous development activities are undertaken beyond the primary term of the lease.

	2009(a)		2010		2011		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net

Core Operating Areas:								
New Mexico Permian	5,241	1,912	7,453	2,922	2,846	1,145	36,751	11,584
Texas Permian	6,498	2,467	6,233	549	5,990	1,088		
Emerging plays and other	88,413	28,387	41,612	16,951	11,839	9,538	8,420	4,896
Total	100,152	32,766	55,298	20,422	20,675	11,771	45,171	16,480

(a) Due to market conditions and prioritization of capital, we have deemphasized exploration efforts in certain emerging plays having significant lease expirations over the next two years, which includes the Delaware Basin, Central Basin Platform and Arkoma Basin in Arkansas. We have impaired a significant portion of the costs associated with these plays.

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Productive wells

The following table sets forth the number of productive oil and gas wells on our properties at December 31, 2008:

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
Core Operating Areas:						
New Mexico Permian	1,515	192	1,707	967.3	55.8	1,023.1
Texas Permian	1,625	71	1,696	381.0	13.7	394.7
Emerging plays and other	61	89	150	8.5	5.3	13.8
Total	3,201	352	3,553	1,356.8	74.8	1,431.6

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 more 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 known 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 properties, we perform title reviews on the most significant properties 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 credit facility, 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 party to the legal proceedings that are described in Note K of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. We are also party to other proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations.

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

We did not submit any matters to a vote of stockholders during the fourth quarter of 2008.

PART II

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

Market Information

Our common stock trades on the NYSE under the symbol CXO. The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on 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
2008:		
First Quarter	$ 26.44	$ 17.33
Second Quarter	$ 40.97	$ 25.12
Third Quarter	$ 39.07	$ 22.31
Fourth Quarter	$ 27.79	$ 14.71

The last sale price of our common stock on February 23, 2009 was $20.50 per share, as reported on the NYSE.

As of February 23, 2009, there were approximately 13,020 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. Our credit facility prohibits the payment of dividends on our common stock.

Repurchase of Equity Securities

Neither we nor any affiliated purchaser repurchased any of our equity securities during the fourth quarter of the fiscal year ended December 31, 2008.

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 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 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. became 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;

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On December 7, 2004, Concho Equity Holdings Corp. acquired oil and gas assets for approximately $117 million and commenced oil and gas operations;

On February 27, 2006, the initial closing of the Chase Oil transaction occurred, and we acquired the Chase Group Properties for approximately 35 million shares of common stock and approximately $409 million in cash;

On March 27, 2007, we entered into a $200 million second lien term loan facility from which we received proceeds of $199 million that we used to repay the $39.8 million outstanding under our prior term loan facility and to reduce the outstanding balance under our credit facility by $154 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes;

In August 2007, we completed our initial public offering of common stock from which we received proceeds of $173 million that we used to retire outstanding borrowings under our second lien term loan facility totaling $86.5 million, and to retire outstanding borrowings under our credit facility totaling $86.5 million; and

On July 31, 2008, we closed our acquisition of the Henry Entities and additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. We paid approximately $584.1 million in net cash for the acquisition of the Henry Entities and the related acquisition of the along-side interests, which was funded with borrowings under our credit facility, which was amended and restated on July 31, 2008, and net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock.

The historical financial data below for the Chase Group Properties for the years ended December 31, 2005 and 2004 are derived from the audited financial statements of the Chase Group Properties. The historical financial data below for Concho Resources Inc. for the years ended December 31, 2008, 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,**	**Years Ended December 31,**	
	2008(a)	**2007**	**2006(b)**	**2005**	**2004(c)**	**2005**	**2004**
	(In thousands, except per share amounts)						
Statement of operations data:							
Operating revenues:							
Oil sales	$ 390,945	$ 195,596	$ 131,773	$ 31,621	$ 1,851	$ 73,132	$ 66,529
Natural gas sales	142,844	98,737	66,517	23,315	1,771	46,546	41,247
Total operating revenues	533,789	294,333	198,290	54,936	3,622	119,678	107,776

Operating costs and expenses:							
Oil and gas production	91,234	54,267	37,822	14,635	746	23,277	20,964
Exploration and abandonments	38,468	29,098	5,612	2,666	1,850		179
Depreciation, depletion and amortization	123,912	76,779	60,722	11,485	956	18,646	20,196
Accretion of discount on asset retirement obligations	889	444	287	89	7	446	263
Impairments of long-lived assets	18,417	7,267	9,891	2,295		194	3,233
General and administrative	35,553	21,336	12,577	8,055	3,086	1,702	1,387
Stock-based compensation	5,223	3,841	9,144	3,252	1,128		
Bad debt expense	2,905						
Contract drilling fees stacked rigs		4,269					

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	Concho Resources Inc.					Chase Group Properties	
	Years Ended December 31,				Inception (April 21, 2004) through December 31,	Years Ended December 31,	
	2008(a)	2007	2006(b)	2005	2004(c)	2005	2004
	(In thousands, except per share amounts)						
Ineffective portion of cash flow hedges	(1,336)	821	(1,193)	1,148			
(Gain) loss on derivatives not designated as hedges	(249,870)	20,274		5,001	(684)	1,062	7,936
Total operating costs and expenses	65,395	218,396	134,862	48,626	7,089	45,327	54,158
Income (loss) from operations	468,394	75,937	63,428	6,310	(3,467)	74,351	53,618
Other income (expense):							
Interest expense	(29,039)	(36,042)	(30,567)	(3,096)	(272)		
Other, net	1,432	1,484	1,186	779	168		
Total other expense	(27,607)	(34,558)	(29,381)	(2,317)	(104)		
Income (loss) before income taxes	440,787	41,379	34,047	3,993	(3,571)	74,351	53,618
Income tax (expense) benefit	(162,085)	(16,019)	(14,379)	(2,039)	915		
Net income (loss)	278,702	25,360	19,668	1,954	(2,656)	$ 74,351	$ 53,618
Preferred stock dividends		(45)	(1,244)	(4,766)	(804)		
Effect of induced conversion of preferred stock			11,601				
Net income (loss) applicable to common shareholders	$ 278,702	$ 25,315	$ 30,025	$ (2,812)	$ (3,460)		

Basic earnings (loss) per share:					
Net income (loss) per share	$ 3.52	$ 0.39	$ 0.63	$ (0.70)	$ (3.48)
Shares used in basic earnings (loss) per share	79,206	64,316	47,287	4,059	994
Diluted earnings (loss) per share:					
Net income (loss) per share	$ 3.46	$ 0.38	$ 0.59	$ (0.70)	$ (3.48)
Shares used in diluted earnings (loss) per share	80,587	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,**	
	2008(a)	**2007**	**2006(b)**	**2005**	**2004(c)**	**2005**	**2004**
				(In thousands)			
Other financial data:							
Net cash provided by (used in) operations	$ 391,397	$ 169,769	$ 112,181	$ 25,070	$ (2,193)	$ 93,162	$ 84,202
Net cash provided by (used in) investing	(946,050)	(160,353)	(596,852)	(61,902)	(122,473)	(35,611)	(30,045)
Net cash provided by (used in) financing	541,981	19,886	476,611	45,358	125,322	(57,551)	(54,157)
Capital expenditures	1,185,831	190,634	1,226,180	72,758	116,880	32,352	25,451

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	December 31,					December 31,	
	2008(a)	2007	2006(b)	2005	2004(c)	2005	2004
Balance sheet data:							
Cash and cash equivalents	$ 17,752	$ 30,424	$ 1,122	$ 9,182	$ 656	$	$
Property and equipment, net	2,401,404	1,394,994	1,320,655	170,583	115,455	149,042	135,568
Total assets	2,815,203	1,508,229	1,390,072	232,385	130,717	161,792	145,100
Long-term debt, including current maturities	630,000	327,404	495,500	72,000	53,000		
Equity	1,325,154	775,398	575,156	109,670	71,710	150,814	134,014

(a) The acquisition of the Henry Entities occurred on July 31, 2008. See Note D of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(b) The acquisition of the Chase Group Properties was substantially consummated on February 27, 2006. See Note D of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(c) 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

On December 7, 2004, we acquired the Lowe Properties for $117 million. The selected financial data below for the Lowe Properties for the period from January 1, 2004 through November 30, 2004 were derived from the audited statements of revenue and direct 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.

	Period from January 1, through November 30, 2004 (In thousands)
Revenues	$ 34,663
Direct operating expenses:	

Lease operating expense		6,983
Production tax expense		2,159
Other expenses		461
Total operating costs and expenses		9,603
Revenues in excess of direct operating expenses	$	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 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, revenues 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 core operations are primarily focused in the Permian Basin of Southeastern New Mexico and West Texas. We have also acquired significant acreage positions in and are actively involved in drilling or participating in drilling in emerging plays located in the Permian Basin of Southeastern New Mexico and the Williston Basin in North Dakota, where we are applying horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. Crude oil comprised 62.9 percent of our 137.3 MMBoe of estimated net proved reserves at December 31, 2008, and 64.8 percent of our 7.1 MMBoe of production for 2008. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 93.1 percent of our proved developed producing PV-10 and 64.7 percent of our 3,553 gross wells at December 31, 2008. 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.

Commodity prices

Factors that may impact future commodity prices, including the price of oil and natural gas, include developments generally impacting the Middle East and Iraq and Iran specifically; the extent to which members of the OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas; the overall global demand for crude oil; and overall North American gas supply and demand fundamentals, including the impact of the decline of the U.S. economy, weather conditions and liquefied natural gas deliveries to the United States. Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our commodity hedge positions at December 31, 2008.

The 2008 oil prices were high compared to historical prices and have been particularly volatile. The NYMEX crude oil price per Bbl averaged $99.75, $72.45 and $66.26 for 2008, 2007 and 2006, respectively. In addition, natural gas prices have been subject to significant fluctuations during the past several years. The NYMEX natural gas price per MMBtu averaged $7.41, $6.11 and $6.06 for 2008, 2007 and 2006, respectively. Further demonstrating the continuing volatility the NYMEX crude oil price and NYMEX natural gas price reached lows of $33.98 per Bbl and $4.08 per MMBtu, respectively, during the period from January 1, 2009 to February 19, 2009. At February 19, 2009, the NYMEX crude oil price and NYMEX natural gas price were $39.48 per Bbl and $4.08 per MMBtu, respectively.

Recent events

Henry Entities acquisition. On July 31, 2008, we closed our acquisition of the Henry Entities and additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. We paid approximately $584.1 million in net cash for the acquisition of the Henry Entities and the related acquisition of the along-side interests, which was funded with borrowings under our credit facility, which was amended and restated on July 31, 2008, and net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock.

Amended and restated credit facility. On July 31, 2008, we amended and restated our credit facility in various respects, including increasing our borrowing base to $960 million, subject to scheduled semiannual redeterminations, and extending the maturity date from February 24, 2011 to July 31, 2013. The initial borrowing under the credit facility was $675 million. We paid an arrangement fee of $14.4 million upon closing of the amended and restated credit facility. On July 31, 2008, we repaid all amounts outstanding under our 2nd lien credit facility and terminated the facility. In October 2008, our $960 million borrowing base was reaffirmed until the next scheduled borrowing base redetermination in April 2009. Between scheduled borrowing base redeterminations, we and, if requested by 662/3 percent of the lenders, the lenders may each request one special redetermination.

Common stock private placement. On July 31, 2008, we closed a private placement of approximately 8.3 million shares of our common stock at $30.11 per share. The private placement resulted in net proceeds of approximately $242.4 million to us, after payment of approximately $7.6 million for the fee paid to the placement agent.

2009 capital budget. On November 6, 2008, our board of directors approved an initial capital budget for 2009 of up to approximately $500 million, predicated on us funding it substantially within our cash flow. The following is a summary of our initial 2009 capital budget:

	2009 Budget (In millions)	
Drilling and recompletion opportunities in our core operating area	$	398
Projects operated by third parties		8
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical		72
Maintenance capital in our core operating areas		22
Total 2009 capital budget	$	500

In light of the recent drop in commodity prices, we took the following actions in January 2009:

- reduced our operated drilling rig count in the Wolfberry play from eight to five;
- deferred our deepening program on our Southeastern New Mexico shelf properties; and
- deferred certain drilling activity in the Lower Abo horizontal play.

The annualized effect of these changes in operating activity would reduce our 2009 capital spending to approximately $300 million, assuming our current estimate of 2009 capital costs. We will monitor our capital expenditures in relation to our cash flow and expect to adjust our activity and capital spending level based on changes in commodity prices and the cost of goods and services and other considerations.

Short-term interruptions in production. During 2008, our production was interrupted on several occasions. The following were significant interruptions:

- None of our properties and facilities were directly impacted by Hurricane Ike; however, facilities which ultimately received our production, primarily natural gas liquids, sustained power interruptions and physical damage. As a result, our production was either curtailed or shut-in for significant periods of time. As a result, we estimate that our September 2008 production was reduced by approximately 117 MBoe and our October 2008 production was reduced by approximately 33 MBoe;
- On May 16, 2008, a refinery located in New Mexico shut down for ten days due to repairs. As a result, we shut-in approximately 37 MBoe of production during the ten day period;
- On April 7, 2008, a natural gas processing plant through which we process and sell a portion of the production from our New Mexico shelf properties was curtailed for its annual routine maintenance. The plant resumed full

operation on April 19, 2008, and we thereafter began restoring production from all of our properties that had been affected. Approximately 75 MBoe of our production was shut-in as a result of this plant shut-down; and

During the first quarter of 2008, we experienced short-term interruptions in our production on the New Mexico shelf properties due to operational problems with a natural gas processing plant. There were a total of 10 days of curtailment during the first quarter, and approximately 17 MBoe of our production was curtailed during this period.

Derivative financial instrument exposure. At December 31, 2008, the fair value of our financial derivatives was a net asset of $172.4 million. All of our counterparties to these financial derivatives are party to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Pursuant to the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential margin calls on our financial derivative instruments.

In light of the recent drop in commodity prices, most of our commodity derivative instruments are currently in a net asset position to us. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Currently, all of our counterparties are parties to our credit facility, and our credit facility does not allow us to offset amounts we may owe a lender under our credit facility against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. During 2008, we entered into additional commodity derivative contracts to hedge a portion of our estimated future production. The following table summarizes information about these additional commodity derivative contracts at December 31, 2008:

	Aggregate Remaining Volume	Daily Volume		Index Price	Remaining Contract Period
Crude oil (volumes in Bbls):					
Price collar	768,000	2,104	$	120.00 - $134.60(a)	1/1/09 - 12/31/09
Price swap	292,000	800	$	98.35(a)	1/1/09 - 12/31/09
Price swap	348,000	953	$	125.10(a)	1/1/09 - 12/31/09
Price swap	240,000	658	$	128.80(a)	1/1/10 - 12/31/10
Price swap	336,000	921	$	128.66(a)	1/1/11 - 12/31/11
Price swap	504,000	1,377	$	127.80(a)	1/1/12 - 12/31/12
Natural gas (volumes in MMBtus):					
Price swap	1,825,000	5,000	$	8.44(b)	1/1/09 - 12/31/09
Index basis swap	6,022,500	16,500	$	1.08(c)	1/1/09 - 12/31/09

(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) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

Commodity derivative contracts assumed in the Henry Entities acquisition. As part of the Henry Entities acquisition, we assumed the following commodity derivative contracts on July 31, 2008. The following table summarizes information about the remaining portion of these assumed derivative contracts at December 31, 2008:

	Aggregate Remaining Volume	Daily Volume	Index Price	Remaining Contract Period
Crude oil (volumes in Bbls):				
Price swap	443,491	1,215	$ 73.59(a)	1/1/09 - 12/31/09

Price swap	401,746	1,101	$ 72.03(a)	1/1/10 - 12/31/10
Price swap	221,746	608	$ 68.92(a)	1/1/11 - 12/31/11

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

New interest rate derivative contracts. During 2008, we entered into interest rate derivative contracts to hedge a portion of our future interest rate exposure. We hedged our LIBOR interest rate on our bank debt by fixing the rate at 1.90 percent for three years beginning in May of 2009 on $300 million of our bank debt. For this portion of our bank debt, the all-in interest rate will be calculated by adding the fixed rate of 1.90 percent to a margin that ranges from 1.25 percent to 2.00 percent depending on the amount of bank debt outstanding.

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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:

On February 24, 2006, we entered into a combination agreement in which we agreed to purchase the Chase Group Properties and combine them with substantially all of the outstanding equity interests of Concho Equity Holdings Corp. to form Concho. 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. became our wholly owned subsidiary. 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;

On February 27, 2006, the initial closing of the Chase Oil transaction occurred, and we acquired the Chase Group Properties for approximately 35 million shares of common stock and approximately $409 million in cash;

On March 27, 2007, we entered into a $200 million second lien term loan facility from which we received proceeds of $199 million that we used to repay the $39.8 million outstanding under our prior term loan facility and to reduce the outstanding balance under our credit facility by $154 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes;

In August 2007, we completed our initial public offering of common stock from which we received proceeds of $173 million that we used to retire outstanding borrowings under our second lien term loan facility totaling $86.5 million, and to retire outstanding borrowings under our credit facility totaling $86.5 million; and

On July 31, 2008, we closed our acquisition of the Henry Entities and additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. We paid approximately $584.1 million in net cash for the acquisition of the Henry Entities and the related acquisition of the along-side interests, which was funded with borrowings under our credit facility, which was amended and restated on July 31, 2008, and net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock.

Results of Operations

The following table presents selected financial and operating information for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	**2007**	**2006**
	(In thousands, except price and daily volume data)		
Statement of operations data:			

Oil sales	$ 390,945	$ 195,596	$ 131,773
Natural gas sales	142,844	98,737	66,517
Total operating revenues	533,789	294,333	198,290
Operating costs and expenses (excluding gains (losses) on derivatives not designated as hedges)	(315,265)	(198,122)	(134,862)
Gains (losses) on derivatives not designated as hedges	249,870	(20,274)	
Interest, net and other revenue	(27,607)	(34,558)	(29,381)
Income before income taxes	440,787	41,379	34,047

	Years Ended December 31,		
	2008	**2007**	**2006**
	(In thousands, except price and daily volume data)		
Income tax expense	(162,085)	(16,019)	(14,379)
Net income	$ 278,702	$ 25,360	$ 19,668
Net production volumes:			
Oil (MBbl)	4,586	3,014	2,295
Natural gas (MMcf)	14,968	12,064	9,507
Total (MBoe)	7,081	5,025	3,880
Average daily production volumes:			
Oil (Bbl)	12,530	8,258	6,288
Natural gas (Mcf)	40,896	33,052	26,047
Total (Boe)	19,347	13,767	10,630
Average prices:			
Oil, without hedges (Bbl)	$ 91.92	$ 68.58	$ 60.47
Oil, with hedges (Bbl)	$ 85.25	$ 64.90	$ 57.42
Natural gas, without hedges (Mcf)	$ 9.59	$ 8.08	$ 6.87
Natural gas, with hedges (Mcf)	$ 9.54	$ 8.18	$ 7.00
Total, without hedges (Boe)	$ 79.80	$ 60.54	$ 52.62
Total, with hedges (Boe)	$ 75.38	$ 58.56	$ 51.12

Year ended December 31, 2008, compared to year ended December 31, 2007

Oil and gas revenues. Revenue from oil and gas operations was $533.8 million for the year ended December 31, 2008, an increase of $239.5 million (81 percent) from $294.3 million for the year ended December 31, 2007. This increase was primarily due to (i) the acquisition of the Henry Entities on July 31, 2008, (ii) increased production due to successful drilling efforts during 2008 and (iii) substantial increases in realized oil and gas prices. In addition:

- average realized oil prices (after giving effect to hedging activities) were $85.25 per Bbl during the year ended December 31, 2008, an increase of 31 percent from $64.90 per Bbl during the year ended December 31, 2007;

- total oil production was 4,586 MBbl for the year ended December 31, 2008, an increase of 1,572 MBbl (52 percent) from 3,014 MBbl for the year ended December 31, 2007;

- average realized natural gas prices (after giving effect to hedging activities) were $9.54 per Mcf during the year ended December 31, 2008, an increase of 17 percent from $8.18 per Mcf during the year ended December 31, 2007;

- total natural gas production was 14,968 MMcf for the year ended December 31, 2008, an increase of 2,904 MMcf (24 percent) from 12,064 MMcf for the year ended December 31, 2007;

- average realized barrel of oil equivalent prices (after giving effect to hedging activities) were $75.38 per Boe during the year ended December 31, 2008, an increase of 29 percent from $58.56 per Boe during the year ended December 31, 2007; and total production was 7,081 MBoe for the year ended December 31, 2008, an increase of 2,056 MBoe (41 percent) from 5,025 MBoe for the year ended December 31, 2007.

See discussion in Recent events for information about our 2008 production interruptions.

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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 in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our annual capital budget and expenditure plans and (iii) lock-in commodity prices to protect economics related to certain capital projects. The following is a summary of the effects of commodity hedges that qualify for hedge accounting treatment for the year ended December 31, 2008 and 2007:

	Crude Oil Hedges Years Ended December 31,		Natural Gas Hedges Years Ended December 31,	
	2008	**2007**	**2008**	**2007**
Hedging revenue increase (decrease) (in thousands)	$ (30,591)	$ (11,091)	$ (696)	$ 1,291
Hedged volumes (Bbls and MMBtus, respectively)	951,000	1,076,750	4,941,000	6,482,600
Hedged revenue increase (decrease) per hedged volume	$ (32.17)	$ (10.30)	$ (0.14)	$ 0.20

During the year ended December 31, 2008, our commodity price hedges decreased oil revenues by $30.6 million ($6.67 per Bbl). During the year ended December 31, 2007, our commodity price hedges decreased oil revenues by $11.1 million ($3.68 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the year ended December 31, 2008 compared to their effect of decreasing oil revenues during the year ended December 31, 2007 was the result of (i) a higher average market price of NYMEX crude oil of $99.75 per Bbl in 2008 as compared to $72.45 per Bbl in 2007 and (ii) the greater price difference between NYMEX and the weighted average hedge price in 2008 as compared to 2007, partially offset by a lower amount of hedged volumes of 951,000 Bbls in 2008 as compared to 1,076,750 Bbls in 2007.

During the year ended December 31, 2008, our commodity price hedges decreased gas revenues by $0.7 million ($0.05 per Mcf) as a result of the amount reclassified from accumulated other comprehensive income (AOCI) into natural gas revenues from cash flow hedges that were dedesignated at June 30, 2007. Cash settlements for these dedesignated natural gas contracts were recorded as a gain on derivatives not designated as hedges. During the year ended December 31, 2007, our commodity price hedges increased gas revenues by $1.3 million ($0.11 per Mcf) primarily as a result of the amount reclassified from AOCI to natural gas revenues from cash flow hedges that were dedesignated at June 30, 2007.

At 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, amounts in AOCI at June 30, 2007 related to these dedesignated hedges remained in AOCI and are reclassified into earnings under natural gas revenues during the periods which the hedged forecasted transaction affects earnings. Cash settlements for these natural gas contracts are recorded to gains (losses) 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 $0.2 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 $1.1 million was reclassified from AOCI to natural gas revenues and cash settlement receipts of $1.8 million was recorded to gains (losses) on derivatives not designated as hedge. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

The above discussion on hedging activities does not represent the activities from all of our commodity derivative instruments. We have other commodity derivative instruments that we do not designate as hedges for accounting purposes. For further discussion and information see Gains (losses) on derivative instruments not designated as hedges below and Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

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Oil and gas production costs. The following tables provide the components of our oil and gas production costs for the year ended December 31, 2008 and 2007:

	Years Ended December 31,			
	2008		2007	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Lease operating expenses	$ 43,725	$ 6.17	$ 26,480	$ 5.27
Taxes:				
Ad valorem	2,738	0.39	2,012	0.40
Production	43,775	6.18	24,301	4.84
Workover costs	996	0.14	1,474	0.29
Total oil and gas production expenses	$ 91,234	$ 12.88	$ 54,267	$ 10.80

Among the cost components of production expenses, in general, we have control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $43.7 million ($6.17 per Boe) for the year ended December 31, 2008, an increase of $17.2 million (65 percent) from $26.5 million ($5.27 per Boe) for the year ended December 31, 2007. The increase in lease operating expenses is due to (i) the wells acquired in the Henry Properties acquisition, which increased the absolute and per unit amount because those wells have a higher per unit cost as compared to our historical per unit cost, (ii) our wells successfully drilled and completed in 2008 and (iii) general inflation of field service and supply costs associated with rising commodity prices.

Ad valorem taxes have increased primarily as a result of (i) the Henry Properties acquisition and (ii) the increase in commodity prices.

Production taxes per unit of production were $6.18 per Boe during the year ended December 31, 2008, an increase of 28 percent from $4.84 per Boe during the year ended December 31, 2007. The increase is directly related to the increase in oil and gas revenues and the related increase in commodity prices. Over the same period our Boe prices (before the effects of hedging) increased 32 percent.

Workover expenses were $1.0 million and $1.5 million for the year ended December 31, 2008 and 2007, respectively. The 2008 amount related primarily to workovers in Andrews County, Texas, while the 2007 amount related to a workover project on a property located in Gaines County, Texas.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the year ended December 31, 2008 and 2007:

	Years Ended December 31,	
	2008	2007
	(In thousands)	

Geological and geophysical	$ 3,139	$ 4,089
Exploratory dry holes	3,723	21,923
Leasehold abandonments and other	31,606	3,086
Total exploration and abandonments	$ 38,468	$ 29,098

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the year ended December 31, 2008 was $3.1 million, a decrease of $1.0 million from $4.1 million for the year ended December 31, 2007. This decrease is primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007.

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Our exploratory dry hole expense during the year ended December 31, 2008 is primarily attributable to an unsuccessful operated exploratory well located in the Central Basin Platform. Our exploratory dry hole expense during the year ended December 31, 2007 is primarily attributable to five unsuccessful operated exploratory wells. The costs associated with three of these wells drilled in the Western Delaware Basin in Culberson County, Texas, approximated $17.0 million. Another of these wells, which was drilled in Lea County, New Mexico, had costs of approximately $2.4 million. An additional $0.8 million was charged to exploratory dry hole costs relative to a target zone in the fifth of these wells in Eddy County, New Mexico, which was determined to be unsuccessful.

For the year ended December 31, 2008, we recorded $31.6 million of leasehold abandonments, which relates primarily to the write-off of (i) our Fayetteville acreage position in Arkansas and (ii) a prospect in the Central Basin Platform in West Texas. For the year ended December 31, 2007, we recorded $3.1 million of leasehold abandonments, of which $0.7 million related to a prospect in Lea County, New Mexico, $0.8 million related to one prospect located in Edwards County, Texas and $0.5 million related to leasehold expiring in Southeastern New Mexico. The remaining $1.1 million was related to several individually minor leaseholds.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the year ended December 31, 2008 and 2007:

	Years Ended December 31,			
	2008		2007	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Depletion of proved oil and gas properties	$ 121,464	$ 17.15	$ 75,744	$ 15.07
Depreciation of other property and equipment	1,808	0.26	1,035	0.21
Amortization of intangible asset operating rights	640	0.09		
Total depletion, depreciation and amortization	$ 123,912	$ 17.50	$ 76,779	$ 15.28
Crude oil price used to estimate proved oil reserves at period end	$ 41.00		$ 92.50	
Natural gas price used to estimate proved gas reserves at period end	$ 5.71		$ 6.80	

Depletion of proved oil and gas properties was $121.5 million ($17.15 per Boe) for the year ended December 31, 2008, an increase of $45.8 million from $75.7 million ($15.07 per Boe) for the year ended December 31, 2007. The increase in depletion expense was primarily due to (i) the Henry Properties acquisition for which the depletion rate was higher than that of our historical assets, (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2007 and 2008 and (iii) the decrease in the oil and natural gas prices between the years which were utilized to determine the proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Henry Properties acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. In accordance with SFAS No. 144, we periodically 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, 2008, we recognized a non-cash charge against earnings of $18.4 million, which was comprised primarily of a fields in Reeves and Upton Counties, Texas and in North Dakota. For the year ended December 31, 2007, we recognized a non-cash charge against earnings of $7.3 million, 33 percent of which related to a field in Gaines County, Texas, 30 percent of which related to a field in Schleicher County, Texas, and 18 percent of which related to a field in Crane County, Texas. The remaining 19 percent was comprised of multiple immaterial wells in various counties.

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General and administrative expenses. The following table provides components of our general and administrative expenses for the year ended December 31, 2008 and 2007:

	Years Ended December 31,			
	2008		2007	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
General and administrative expenses recurring	$ 36,170	$ 5.11	$ 22,419	$ 4.46
Non-recurring bonus paid to Henry Entities employees, see Note K	4,328	0.61		
Non-cash stock-based compensation stock options	3,101	0.44	2,463	0.49
Non-cash stock-based compensation restricted stock	2,122	0.30	1,378	0.27
Less: Third-party operating fee reimbursements	(4,945)	(0.70)	(1,083)	(0.21)
Total general and administrative expenses	$ 40,776	$ 5.76	$ 25,177	$ 5.01

General and administrative expenses were $40.8 million ($5.76 per Boe) for the year ended December 31, 2008, an increase of $15.6 million (62 percent) from $25.2 million ($5.01 per Boe) for the year ended December 31, 2007. The increase in general and administrative expenses during the year ended December 31, 2008 over 2007 was primarily due to (i) the non-recurring bonus paid to Henry Entities employees, (ii) an increase in non-cash stock-based compensation for both stock options and restricted stock awards and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

As part of the Henry Entities acquisition, we agreed to pay certain of the Henry Entities employees a predetermined bonus amount, in addition to the compensation we pay these employees, over the next two years. Since these employees will earn this bonus over the next two years we are reflecting the cost in our general and administrative costs. We are reflecting this bonus amount as non-recurring as it is not controlled by our management. See Note K of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information related to this bonus.

We earn reimbursements as operator of certain oil and gas properties in which we own interests. As such, we earned reimbursements of $4.9 million and $1.1 million during the year ended December 31, 2008 and 2007, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is directly related to the Henry Properties acquisition, as we own a lower working interest in these operated properties compared to our historical property base, thus we have a larger third-party reimbursement as compared to our historical property base.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to sell a portion of our oil production affected by a New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount of $2.9 million due from this purchaser for June and July production during the year ended December 31, 2008.

Contract drilling fees stacked rigs. 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 year ended December 31, 2007 of approximately $4.3 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. 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.

Gains (losses) on derivatives not designated as hedges. As discussed in Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data, during the three months ended June 30, 2007, we determined that all of our natural gas commodity derivative 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. In addition, for our new commodity and interest rate derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period.

For the year ended December 31, 2008, the related cash payments for settlements for derivative contracts not designated as hedges was approximately $6.3 million. The non-cash mark-to-market adjustment for the derivative contracts not designated as hedges was a gain of $256.2 million. This is compared to cash receipts for settlements of $1.8 million and non-cash mark-to-market losses of $22.1 million for the year ended December 31, 2007.

Interest expense. Interest expense was $29.0 million for the year ended December 31, 2008, a decrease of $7.0 million from $36.0 million for the year ended December 31, 2007. The weighted average interest rate for the year ended December 31, 2008 and 2007 was 5.1 percent and 7.7 percent, respectively. The weighted average debt balance during the year ended December 31, 2008 and 2007 was approximately $450.7 million and $436.3 million, respectively.

The increase in weighted average debt balance during the year ended December 31, 2008 was due to the Henry Properties acquisition in July 2008, offset by (i) the partial prepayment in August 2007 of $86.6 million on the 2nd lien credit facility and the repayment in August 2007 of $86.6 million on our previous revolving credit facility and (ii) a partial prepayment in March 2008 on our previous revolving credit facility utilizing cash from operations. Also, in July 2008, we repaid and terminated our 2nd lien credit facility which resulted in the write-off of approximately $1.1 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. In March 2007, we reduced our previous revolving credit facility s borrowing base by $100.0 million, or 21%, resulting in the write-off of $0.8 million of deferred loan costs, and repaid a term credit facility, resulting in the write-off of $0.4 million of deferred loan costs, both of which are included in interest expense. In August 2007, we made a $86.6 million partial prepayment on our 2nd lien credit facility from proceeds of our initial public offering, which resulted in the write-off of approximately $1.0 million of deferred loan costs and approximately $0.4 million of original issue discount, both of which are included in interest expense. The decrease in the weighted average interest rate is due to (i) improvement in market interest rates and (ii) the fact that the interest rate margins under our credit facility (and previous revolving credit facility) were lower than those under our 2nd lien credit facility.

Income tax provision. We recorded an income tax expense of $162.1 million and $16.0 million for the year ended December 31, 2008 and 2007, respectively. The effective income tax rate for the year ended December 31, 2008 and 2007 was 36.8 percent and 38.7 percent, respectively. We estimated a higher effective state income rate in 2007 than in 2008, which is primarily due to our estimate of income among the various states in which we own assets.

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

Oil and gas revenues. Revenue from oil and gas operations was $294.3 million for the year ended December 31, 2007, an increase of $96.0 million (48 percent) from $198.3 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 percent 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 percent) from 2,295 MBbl 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 percent 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 percent) from 9,507 MMcf for the year ended December 31, 2006;

average realized barrel of crude oil equivalent prices (after giving effect to hedging activities) were $58.56 per Boe during the year ended December 31, 2007, an increase of 15 percent from $51.12 per Boe during the year ended December 31, 2006;

total production was 5,025 MBoe for the year ended December 31, 2007, an increase of 1,145 MBoe (30 percent) from 3,880 MBoe for the year ended December 31, 2006; and

total production during the year ended December 31, 2007 was reduced by approximately 110 MBoe 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.

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 in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our annual capital budgeting and expenditure plans and (iii) lock-in commodity prices to protect economics related to certain capital projects. Following is a summary of the effects of commodity hedges that qualify for hedge accounting treatment for the year ended December 31, 2007 and 2006:

	Crude Oil Hedges Years Ended December 31,		Natural Gas Hedges Years Ended December 31,	
	2007	2006	2007	2006
Hedging revenue increase (decrease) (in thousands)	$ (11,091)	$ (7,000)	$ 1,291	$ 1,232
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 $11.1 million ($3.68 per Bbl). During the year ended December 31, 2006, our commodity price hedges decreased oil revenues by $7.0 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 (i) a higher average market price of NYMEX crude oil of $72.45 per Bbl in 2007 as compared to $66.26 per Bbl in 2006, and (ii) 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 in 2007 as compared to 2006.

During the year ended December 31, 2007, our commodity price hedges increased gas revenues by $1.3 million ($0.11 per Mcf). During the year ended December 31, 2006, our commodity price hedges increased gas revenues by $1.2 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 in 2007 as compared to 2006, partially offset by (i) the lower hedged revenue per hedged volume in 2007 as compared to 2006 and (ii) a higher reference market price for natural gas of $6.11 per MMBtu in 2007 as compared to $6.06 per MMBtu in 2006.

At 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. As a result, amounts in AOCI at June 30, 2007 related to these dedesignated hedges remained in AOCI and are reclassified into earnings under natural gas revenues during the periods which the hedged forecasted transaction affects earnings. Cash settlements for these natural gas contracts are recorded to gains (losses) 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 $1.1 million was reclassified from AOCI to natural gas revenues and cash settlement receipts of $1.8 million was recorded to gains (losses) on derivatives not designated as hedge. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Oil and gas production costs. The following tables provide the components of our oil and gas production costs for the year ended December 31, 2007 and 2006:

	Years Ended December 31,			
	2007		2006	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Lease operating expenses	$ 26,480	$ 5.27	$ 20,424	$ 5.26
Taxes:				
Ad valorem	2,012	0.40	1,120	0.29
Production	24,301	4.84	15,762	4.06
Workover costs	1,474	0.29	516	0.14
Total oil and gas production expenses	$ 54,267	$ 10.80	$ 37,822	$ 9.75

Among the cost components of production expenses, in general, we have control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $26.5 million ($5.27 per Boe) for the year ended December 31, 2007, an increase of $6.1 million (30 percent) from $20.4 million ($5.27 per Boe) for the year ended December 31, 2006. The increase in lease operating expenses is due to (i) lease operating expenses associated with the Chase Group Properties acquired in February 2006 of approximately $2.2 million, (ii) lease operating expenses associated with wells that were successfully completed in 2006 and 2007 as a result of our drilling activities and (iii) general inflation of field service and supply costs associated with rising commodity prices.

Ad valorem taxes have increased primarily as a result of (i) new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities and (ii) the increase in commodity prices.

Production taxes per unit of production were $4.84 per Boe during the year ended December 31, 2007, an increase of 19 percent from $4.06 per Boe during the year ended December 31, 2006. The increase is directly related to the increase in oil and gas revenues and the related increase in commodity prices. Over the same period our Boe prices (before the effects of hedging) increased 15 percent.

Workover expenses were $1.5 million and $0.5 million for the year ended December 31, 2007 and 2006, respectively. The 2007 amount related to a workover project on a property located in Gaines County, Texas, while the 2006 amount related primarily to workovers located in Andrews County, Texas.

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:

	Years Ended December 31, 2007	2006
	(In thousands)	
Geological and geophysical	$ 4,089	$ 2,185
Exploratory dry holes	21,923	3,192
Leasehold abandonments and other	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 $4.1 million, an increase of $1.9 million from $2.2 million for the year ended December 31, 2006. This

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87 percent increase is primarily attributable to a comprehensive seismic survey on our New Mexico 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 $17.0 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.4 million. An additional $0.8 million was charged to exploratory dry hole costs related to an unsuccessful targeted zone in the fifth of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico. Exploration expense of $1.7 million related to three unsuccessful outside operated wells located in Eddy County, New Mexico.

Of our exploratory dry holes expense during the year ended December 31, 2006, $3.2 million was attributable to one unsuccessful exploratory well in Gaines County, Texas that we operated and one unsuccessful exploratory well in Val Verde County, Texas operated by another company.

For the year ended December 31, 2007, we recorded $3.1 million of leasehold abandonments, of which $0.7 million related to a prospect in Lea County, New Mexico, $0.8 million related to one prospect located in Edwards County, Texas and $0.5 million related to leasehold expiring in Southeastern New Mexico. The remaining $1.1 million was related to several individually minor leaseholds. We had minimal leasehold abandonments during the year ended December 31, 2006.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the year ended December 31, 2007 and 2006:

	Years Ended December 31,			
	2007		2006	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
Depletion of proved oil and gas properties	$ 75,744	$ 15.07	$ 59,872	$ 15.43
Depreciation of other property and equipment	1,035	0.21	850	0.22
Total depletion, depreciation and amortization	$ 76,779	$ 15.28	$ 60,722	$ 15.65
Crude oil price used to estimate proved oil reserves at period end	$ 92.50		$ 57.75	
Natural gas price used to estimate proved gas reserves at period end	$ 6.80		$ 5.64	

Depletion of proved oil and gas properties was $75.7 million ($15.07 per BOE) for the year ended December 31, 2007, an increase of $15.8 million from $59.9 million ($15.43 per BOE) for the year ended December 31, 2006. The increase in depletion expense was primarily due to (i) the acquisition of the Chase Group Properties and (ii) capitalized costs associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities. The decrease in depletion expense per Boe 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 long-lived assets. 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 $7.3 million, 33 percent of which related to wells drilled in Gaines County, Texas, 30 percent of which related to a well drilled in Schleicher County, Texas and 18 percent of which related to a well drilled in Crane County, Texas. The remaining 19 percent 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 $9.9 million, 33 percent of which related to wells located in Pecos and Midland Counties, Texas, acquired in our Lowe Acquisition, 24 percent of which related to wells located in Lea and Eddy Counties, New Mexico, acquired in our Lowe Acquisition, 11 percent of which related to a well drilled in Eddy County, New Mexico and 9 percent of which related to a well drilled in Mountrail County, North Dakota. The remaining 23 percent was comprised of multiple immaterial wells in various counties.

Contract drilling fees stacked rigs. 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 $4.3 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. The following table provides components of our general and administrative expenses for the year ended December 31, 2007 and 2006:

	Years Ended December 31,			
	2007		2006	
	Amount	Per Boe	Amount	Per Boe
	(In thousands, except per unit amounts)			
General and administrative expenses recurring	$ 22,419	$ 4.46	$ 13,376	$ 3.45
Non-cash stock-based compensation Capital Options			975	0.25
Non-cash stock-based compensation stock options	2,463	0.49	7,125	1.84
Non-cash stock-based compensation restricted stock	1,378	0.27	1,044	0.27
Less: Third-party operating fee reimbursements	(1,083)	(0.21)	(799)	(0.21)
Total general and administrative expenses	$ 25,177	$ 5.01	$ 21,721	$ 5.60

General and administrative expenses were $25.2 million ($5.01 per BOE) for the year ended December 31, 2007, an increase of $3.5 million (16 percent) from $21.7 million ($5.60 per BOE) for the year ended December 31, 2006. The increase in general and administrative expenses during the year ended December 31, 2007 was primarily due to the increase in the size and complexity of our operations following the combination transaction and related increase in professional fees. In addition, annual bonuses in the aggregate amount of $2.5 million were paid to the officers and employees in April 2007 representing bonuses for 2006 performance as compared to $0.9 million aggregate bonuses paid to employees in February 2006.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $1.1 million and $0.8 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.

Gains (losses) on derivatives not designated as hedges. As discussed in Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data, during the three months ended June 30, 2007, we determined that all of our natural gas commodity derivative 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. In addition, for our new commodity and interest rate derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period.

This is compared to cash receipts for settlements of $1.8 million and non-cash mark-to-market losses of $22.1 million for the year ended December 31, 2007.

Interest expense. Interest expense was $36.0 million for the year ended December 31, 2007, an increase of $5.6 million from $30.6 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 percent and 7.5 percent, respectively. The weighted average debt balance during the year ended December 31, 2007 and 2006 was approximately $436.3 million and $406.8 million, respectively.

The increase in weighted average debt balance during the year ended December 31, 2007 was our borrowings to fund our drilling activities, partially offset by the partial prepayment in August 2007 of $86.6 million on our

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2nd lien credit facility and the repayment in August 2007 of $86.6 million on our then revolving 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 our then revolving credit facility borrowing base by $100.0 million, or 21 percent, resulting in accelerated amortization of $0.8 million, and the full repayment of the 2nd lien credit facility resulting in accelerated amortization of $0.4 million. The prepayment of $86.6 million on our New 2nd lien credit facility in August 2007 resulted in accelerated amortization of $1.0 million in deferred loan costs and $0.4 million in original issue discount.

Income tax provision. We recorded income tax expense of $16.0 million and $14.4 million for the year ended December 31, 2007 and 2006, respectively. The effective income tax rate for the year ended December 31, 2007 and 2006 was 38.7 percent and 42.2 percent, respectively. We estimated a lower effective state income rate in 2007 than in 2006, which is primarily due to our estimate of income among the various states in which we own assets.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, proceeds from the disposition of assets or alternative financing sources as discussed in Capital resources below.

Oil and gas properties. Our capital expenditures on oil and gas properties, excluding acquisitions and asset retirement obligations, during the years ended December 31, 2008, 2007 and 2006 totaled $339.0 million, $180.5 million and $173.0 million, respectively. These expenditures were primarily funded by cash flow from operations.

On November 6, 2008, our board of directors approved an initial capital budget for 2009 of up to approximately $500 million. The capital budget is predicated on us funding it substantially within cash flow. In light of the recent drop in commodity prices we took the following actions in January 2009:

- reduced our operated drilling rig count in the Wolfberry play from eight to five;
- deferred our deepening program on our Southeastern New Mexico shelf properties; and
- deferred certain drilling activity in the Lower Abo horizontal play.

The annualized effect of these changes in operating activity would reduce the Company s 2009 capital spending to approximately $300 million, assuming the Company s current estimate of 2009 capital costs. We will monitor our capital expenditures in relation to our cash flow on a quarterly basis and will adjust our activity and capital spending level based on changes in commodity prices and the cost of goods and services.

Other than leasehold acreage and other property interests, our 2009 capital budget is exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. 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.

Although we cannot provide any assurance, we believe that our remaining cash balance and our cash flows will be sufficient to satisfy our 2009 capital budget; however, we could use our 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 2009 capital budget.

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Acquisitions. Our expenditures for acquisitions of proved and unproved properties during the years ended December 31, 2008, 2007 and 2006 totaled $838.0 million, $7.3 million and $1,044.7 million, respectively. The Henry Properties acquisition in July 2008 was primarily funded by a private placement of our common stock and borrowings under our credit facility. In February 2006, through the combination transaction we acquired the Chase Group Properties which was funded through our credit facility and the issuance of our common stock.

Contractual obligations. Our contractual obligations include long-term debt, operating lease obligations, drilling commitments (including commitments to pay day rates for drilling rigs), employment agreements, contractual bonus payments, derivative obligations and other liabilities.

We had the following contractual obligations at December 31, 2008:

	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)	$ 630,000	$	$	$ 630,000	$
Operating lease obligations(b)	4,743	970	2,955	818	
Drilling commitments(c)	28,730	25,858	2,872		
Employment agreements with executive officers(d)	5,970	2,190	3,780		
Henry Entities bonus obligation(e)	16,446	10,387	6,059		
Derivative assets(f)	(172,440)	(111,283)	(61,157)		
Asset retirement obligations(g)	16,809	2,611	604	598	12,996
Total contractual cash obligations	$ 530,258	$ (69,267)	$ (44,887)	$ 631,416	$ 12,996

(a) See Note J of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data. The amounts included in the table above represent principal maturities only.

(b) See Note K of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(c) Consists of daywork drilling contracts related to drilling rigs contracted for 2009 and 2010. See Note K of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(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. An executive officer resigned as of March 31, 2008, and we will be obligated to pay him 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 us in accordance with his employment agreement. Additionally, Steven L. Beal, our President and Chief Operating Officer, has given notice of his intent to retire from the Company effective June 30, 2009. As a result, only six months of Mr. Beal s salary is included.

(e) Represents bonuses we agreed to pay certain employees of the Henry Entities at each of the first and second anniversaries of the closing of the Henry Properties acquisition. See Note D of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(f) Derivative obligations represent net asset for commodity and interest rate derivatives that were valued at December 31, 2008. The ultimate settlement amounts of our derivative obligations are unknown because they are subject to continuing market risk. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk and Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative obligations.

(g) 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 material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our credit facilities. We believe that funds from operating cash flows and our credit facility should be sufficient to meet both our short-term working capital requirements and our 2009 capital budget plan.

Cash flow from operating activities. Our net cash provided by operating activities was $391.4 million, $169.8 million and $112.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. The increase in operating cash flows during the years ended December 31, 2008 over 2007 was principally due to (i) increases in our oil and gas production as a result of our exploration and development program, (ii) five months of activity from the acquired Henry Properties and (iii) increases in average realized oil and natural gas prices. 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.

Cash flow used in investing activities. During the years ended December 31, 2008, 2007 and 2006, we invested $946.1 million, $162.6 million and $595.6 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, 2008 over 2007, primarily due to the Henry Properties acquisition, as well as increased drilling activity in 2008. Cash flows used in investing activities were substantially higher during the year ended December 31, 2006, primarily due to the approximately $409.0 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 year ended December 31, 2007, until we were able to complete our second lien term loan facility in March 2007.

Cash flow from financing activities. Net cash provided by financing activities was $542.0 million, $19.9 million and $476.6 million for the years ended December 31, 2008, 2007 and 2006, respectively. During the year ended December 31, 2008, we borrowed $767.8 million under our credit facilities and issued approximately 8.3 million shares of our common stock to fund the Henry Properties acquisition. In March 2007, we entered into a $200 million 2nd lien credit 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 credit facility. 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 $409.0 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.

On July 31, 2008, we amended and restated our senior credit facility in various respects, including increasing the borrowing base to $960 million, subject to scheduled semiannual redetermination, and extending the maturity date from February 24, 2011 to July 31, 2013. We paid an arrangement fee of $14.4 million at closing of the credit facility. In October 2008, the borrowing base was reaffirmed at $960 million. The amount outstanding under the credit facility at December 31, 2008 was $630.0 million. Between scheduled borrowing base redeterminations, we and, if requested by 662/3 percent of the lenders, the lenders may each request one special redetermination.

Advances on the credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) or (ii) 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 125 to 275 basis points and zero to 125 basis points, respectively, per annum depending on the balance outstanding. We pay commitment fees on the unused portion of the available borrowing base ranging from 25 to 50 basis points per annum. Our credit facility bore interest at 1.96 percent per annum at December 31, 2008.

On July 31, 2008, we repaid all the amounts outstanding under our 2nd lien credit facility and terminated the facility.

On June 5, 2008, we entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of our common stock in a private placement (the Private Placement) contemporaneous with the closing of the Acquisition. On July 31, 2008, we issued 8,302,894 shares of our common stock at

$30.11 per share pursuant to the Private Placement. We paid the placement agent of the Private Placement a fee of approximately $7.6 million, which resulted in net proceeds to us of $242.4 million.

In conducting our business, we may utilize various financing sources, including (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock and (iv) common stock. We may also sell assets and issue securities in exchange for oil and gas assets or interests in oil and gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our Senior Credit Facility.

Financial markets. The current state of the financial markets is uncertain. There have been financial related institutions that have (i) failed and been forced into government receivership, (ii) declared bankruptcy, (iii) been forced to seek additional capital and liquidity to maintain viability or (iv) merged to survive. The U.S. and world economy is experiencing a slow-down which is having an adverse impact on the financial markets.

At December 31, 2008, we had $329.7 million of borrowing capacity under our credit facility. Even in light of the current uncertainty in the financial markets, we currently believe that our lenders under our credit facility have the ability to fund additional borrowings we may need for our business.

We currently pay floating rate interest under our credit facility and we are unable to predict, especially in light of the current uncertainty in the financial markets, whether we will incur increased interest costs due to rising interest rates. We have utilized the use of interest rate derivatives to mitigate the cost of rising interest rates, and we may do additional interest rate derivatives in the future.

In the current financial markets, we do not believe that we could refinance our credit facility and obtain comparable terms. Since our credit facility matures in July 2013, we have no immediate need to seek refinancing of our credit facility.

To the extent we need additional funds, beyond those available under our credit facility, to operate our business or make acquisitions we would have to pursue other financing sources. These sources could include issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock or (v) other securities. We may also sell assets. However, in light of the current financial markets there are no assurances that we could obtain additional funding, or if available, at what cost and terms.

Liquidity. Our principal sources of short-term liquidity are cash on hand and unused borrowing capacity under our credit facility. At December 31, 2008, we had $17.8 million of cash on hand.

At December 31, 2008, our borrowing base under our credit facility was $960 million, which provides us with $329.7 million of unused borrowing capacity. Our borrowing base is redetermined semi-annually, with the next redetermination occurring in April 2009. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any twelve-month period. In general, redeterminations are based upon a number of factors, including commodity prices and reserve levels. Upon a redetermination, our borrowing base could be substantially reduced. In light of the current commodity prices and the state of the financial community, there is no assurance that our borrowing base will not be reduced.

Book capitalization and current ratio. Our book capitalization at December 31, 2008 was $1,955.2 million, consisting of debt of $630.0 million and stockholders equity of $1,325.2 million. Our debt to book capitalization was 32 percent and 30 percent at December 31, 2008 and 2007, respectively. Our ratio of current assets to current liabilities was 1.03 to 1.00 at December 31, 2008 as compared to 0.84 to 1.00 at December 31, 2007.

Inflation and changes in prices. Our revenues, the value of our assets, our ability to obtain bank funding or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During 2008, we received an average of $91.92 per barrel of oil and $9.59 per Mcf of natural gas before consideration of commodity derivative contracts compared to $68.58 per barrel of oil and $8.08 per Mcf of natural gas in the prior year. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and continued through the first six months of 2008, commodity prices for oil and gas increased significantly. The higher prices have led to

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increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on capital costs. We expect these costs to moderate into 2009 as a result of the recent rapid diminution in prices for oil and natural gas.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and related notes to 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, impairment of long-lived assets and valuation of stock-based compensation. 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.

Depletion 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 depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Discounted 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 depletion and result in impairment of long-lived 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 Long-Lived 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 an asset 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.

Valuation of Stock-Based Compensation

We adopted the modified prospective approach as prescribed under SFAS No. 123(R) on January 1, 2006. Under this approach, we are required to expense all options and other stock-based compensation that vested during the year of adoption based on the fair value of the award on the grant date. The calculation of the fair value of stock-based compensation requires the use of estimates to derive the inputs necessary for using the various valuation methods utilized by us. We utilize (i) the Black-Scholes option pricing model to measure the fair value of stock options and (ii) the stock price on the date of grant for the fair value of restricted stock awards.

Recent Accounting Pronouncements

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 became 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 has not had 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 did not adopt EITF Issue 06-11 until the required effective date of January 1, 2008. The adoption of EITF Issue 06-11 has not had 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. SFAS No. 141(R) 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, 2008 consolidated balance sheet, the statement would have no impact.

In December 2007, the SEC issued Staff Accounting Bulletin (SAB) No. 110, *Share-Based Payment* (SAB No. 110). SAB No. 110 amends SAB No. 107, *Share-Based Payment*, and allows for the continued use, under certain circumstances, of the simplified method in developing an estimate of the expected term on stock options accounted for under SFAS No. 123R, *Share-Based Payment (revised 2004)*. SAB No. 110 is effective for stock options granted after December 31, 2007. We continued to use the simplified method in developing an estimate of the expected term on stock options granted in 2008. We do not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time our shares of common stock have been publicly traded.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161), which amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS No. 133), to provide an enhanced understanding of an entity s use of derivative instruments, how they are accounted for under SFAS No. 133 and their effect on the entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective as of January 1, 2009. We are currently evaluating the impact on our consolidated financial statements of adopting SFAS No. 161.

In April 2008, the FASB issued FASB Staff Position (FSP) No. SFAS No. 142-3, *Determination of the Useful Life of Intangible Assets* (FSP SFAS No. 142-3). FSP SFAS No. 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). The intent of FSP SFAS No. 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R and other applicable accounting literature. FSP SFAS No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. We are currently evaluating the potential impact, if any, of FSP SFAS No. 142-3 on our financial statements.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. This statement is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. We do not expect the adoption of SFAS No. 162 to have an impact on our financial statements.

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 was effective for us on January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retroactively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition, we do not expect the application of FSP EITF 03-6-1 to have a significant impact on our reported earnings per share.

In October 2008, the FASB issued FSP No. SFAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*. FSP No. SFAS 157-3 clarifies the application of SFAS No. 157 as it relates to the valuation of financial assets in a market that is not active for those financial assets. This FSP is effective immediately and includes those periods for which financial statements have not been issued. We currently do not have any financial assets that are valued using inactive markets, and as a result, we are not impacted by the issuance of FSP No. SFAS 157-3.

Recent Developments in Reserve Reporting

The SEC recently approved new disclosure rules that allow oil and natural gas companies to more accurately report their assets in terms of volumes and values that investors can understand and use to make informed decisions. The new reporting requirement is effective on December 15, 2009. The new disclosure requirements include provisions that:

- permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;

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allow companies to disclose in SEC filed documents their probable and possible reserves to investors (currently, the SEC rules limit disclosure to only proved reserves);

require companies to report the independence and qualifications of a reserves preparer or auditor;

file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and

report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices.

We are currently evaluating the impact these new reserve reporting requirements will have on our consolidated financial statements and our annual report on Form 10-K.

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. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2008, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for trading purposes.

Hypothetical changes in interest rates and commodity 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 and properties 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. In this manner, we reduce credit risk.

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. At December 31, 2008, the net unrealized asset on our commodity price risk management contracts was $172.4 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 at December 31, 2008, would have resulted in a decrease in the net unrealized asset on our commodity price risk management contracts, as reflected on our consolidated balance sheet at December 31, 2008, of approximately $3.6 million.

At December 31, 2008, we had (i) a oil price collar and oil price swaps that settle on a monthly basis covering future oil production from January 1, 2008 through December 31, 2012 and (ii) a natural gas price swap and a natural gas basis swap covering future natural gas production for 2009, see Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information on the commodity derivative contracts. The average NYMEX oil futures price and average NYMEX natural gas futures prices for the year ended December 31, 2008, was $99.75 per Bbl and $7.41 per MMBtu, respectively. At February 19, 2008, the NYMEX oil futures price and NYMEX natural gas futures price was $39.48 per Bbl and $4.08 per MMBtu, respectively. The decrease in oil and natural gas prices, should it continue into 2009, should

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increase the fair value asset of our commodity derivative contracts from their recorded balance at December, 2008. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential increase in fair value asset would be recorded in earnings as unrealized gains. However, an increase in the average NYMEX oil and natural gas futures price above those at December 31, 2008 would result in an decrease in fair value asset and unrealized losses in earnings. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

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. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. 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 credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base.

At December 31, 2008, we had interest rate swaps on $300 million of notional principal that fixed the LIBOR interest rate (does not include the interest rate margins discussed above) at 1.90 percent for the three years beginning in May 2009. An average decrease in future interest rates of 25 basis points from the future rate at December 31, 2008, would have resulted in a decrease in the net unrealized asset on our interest rate risk management contracts, as reflected on our consolidated balance sheet at December 31, 2008, of approximately $2.0 million.

We had total indebtedness of $630.0 million outstanding under our credit facility at December 31, 2008. The impact of a 1 percent increase in interest rates on this amount of debt, assuming the interest rate swaps were outstanding, would result in increased annual interest expense of approximately $6.3 million and a corresponding decrease in net income before income tax.

The fair value of our derivative instruments is determined based on counterparties estimates and valuation models. We did not change our valuation method during 2008. During 2008, we were party to commodity and interest rate derivative instruments. See Note I of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during 2008:

	Derivative Instruments Net Assets (Liabilities)(a)		
	Commodities	Interest Rate	Total
		(In thousands)	
Fair value of contracts outstanding at December 31, 2007	$ (45,065)	$	$ (45,065)
Fair value of contracts from acquisitions	(62,662)		(62,662)
Changes in fair values(b)	244,305	(1,083)	243,222
Contract maturities	36,945		36,945
Fair value of contracts outstanding at December 31, 2008	$ 173,523	$ (1,083)	$ 172,440

(a) Represents the fair values of open derivative contracts subject to market risk.

(b) At inception, new derivative contracts entered into by us have no intrinsic value.

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Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements and supplementary financial data are included in this 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. ***Controls and Procedures***

Evaluation of disclosure controls and procedures. The Company s management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Exchange Act, the Company s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Report. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of the Company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits 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 have been no changes in the Company s internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the Company s last fiscal quarter that have materially affected or are reasonably likely to materially affect the Company s internal control over financial reporting.

Henry Properties acquisition. Because the Henry Properties acquisition was completed in the third quarter of 2008 management did not include the internal control processes for these related entities in its assessment of internal control over financial reporting at December 31, 2008. See more details below relating to the exclusion of these acquisitions from Management s Report on Internal Control Over Financial Reporting. Additionally, this acquisition is excluded from the certifications required under Section 302 of the Sarbanes-Oxley Act of 2002, which are attached as exhibits to this report. Management will include all aspects of internal controls for this acquisition in its 2009 assessment. The Henry Properties acquisition represents 33 percent of our total assets at December 31, 2008 and 11 percent of our total revenues for the year ended December 31, 2008.

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company s internal control over financial reporting is a process designed under the supervision of the Company s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2008, management assessed the effectiveness of the Company s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework , issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management excluded from its assessment of internal controls over financial reporting the Henry Properties acquisition, which closed in the third quarter of 2008 and constitute 33 percent of total assets and 11 percent of revenues of the consolidated financial statement amounts as of and for the year ended December 31, 2008. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2008.

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

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued an attestation report on the effectiveness of the Company s internal control over financial reporting as of December 31, 2008. The report, which expresses an unqualified opinion on the effectiveness of the Company s internal control over financial reporting as of December 31, 2008, is included in this Item under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting .

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
Concho Resources Inc.

We have audited Concho Resources Inc. s (a Delaware Corporation) internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Concho Resources Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Concho Resources Inc. s internal control over financial reporting based on our audit. Our audit of, and opinion on, Concho Resources Inc. s internal control over financial reporting does not include internal control over financial reporting of Henry Properties acquisition whose financial statements reflect total assets and revenues constituting 33 percent and 11 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2008. As indicated in Management s Report, the Henry Properties were acquired during 2008 and therefore, management s assertion on the effectiveness of Concho Resources Inc. s internal control over financial reporting excluded internal control over financial reporting of the Henry Properties.

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

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

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

In our opinion, Concho Resources Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Concho Resources Inc. and subsidiaries as of December 31, 2008 and 2007 and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2008, and our report dated February 27, 2009 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP
February 27, 2009
Tulsa, Oklahoma

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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, 2008.

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, 2008.

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

Equity Compensation Plans

At December 31, 2008, 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 descriptions of our stock incentive plan under Note G of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plan approved by security holders(a)	2,731,324	$ 12.46	1,993,507
Equity compensation plan not approved by security holders(b)		$	
Total	2,731,324		1,993,507

(a)

2006 Stock Incentive Plan. See Note G of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data.

(b) None.

The remaining information required by 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, 2008.

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, 2008.

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, 2008.

PART IV

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

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements of the Company are included in Financial Statements and Supplementary Data:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of December 31, 2008 and 2007

Consolidated Statements of Operations for the Years Ended December 31, 2008, 2007 and 2006

Consolidated Statements of Stockholders Equity for the Years Ended December 31, 2008, 2007 and 2006

Consolidated Statements of Cash Flows for the Years Ended December 31, 2008, 2007 and 2006

Notes to Consolidated Financial Statements

Unaudited Supplementary Information

(b) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(b) are listed below and in the Index to Exhibits attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of the Report or they are inapplicable.

Exhibits

Exhibit Number	Exhibit
2.1	Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc., James C. Henry and Paula Henry, Henry Securities Ltd., Henchild LLC, Henry Family Investment Group, Henry Holding LP, Henry Energy LP, Aguasal Holding, HELP Investment LLC, Henry Capital LLC, Henry Operating LLC, Henry Petroleum LP, Quail Ranch LLC, Aguasal Management LLC, and

	Aguasal LP (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on August 6, 2007, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Concho Resources Inc., as amended March 25, 2008 (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on March 26, 2008, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Current Report on Form S-1/A on July 5, 2007, and incorporated herein by reference).

Exhibit Number	Exhibit
10.1	Credit Agreement, dated as of February 24, 2006, by and 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(filed as Exhibit 10.1 to the Company s Current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.2	Second Lien Credit Agreement, dated as of 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 (filed as Exhibit 10.2 to the Company s Current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.3	Form of Drilling Agreement with Silver Oak Drilling, LLC (filed as Exhibit 10.4 to the Company s Current Report on Form S-1/A on July 5, 2007, and incorporated herein by reference).
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 (filed as Exhibit 10.5 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.5	Transition Services Agreement dated April 23, 2007, between COG Operating LLC and Mack Energy Corporation (filed as Exhibit 10.3 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
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 (filed as Exhibit 2.1 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference). The Combination Agreement filed as Exhibit 2.1 omits certain of the schedules and exhibits to the Combination Agreement in accordance with Item 601(b)(2) of Regulation S-K. A list briefly identifying the contents of all omitted schedules and exhibits is included with the Combination Agreement filed as Exhibit 2.1. Concho Resources agrees to furnish supplementally a copy of any omitted schedule or exhibit to the Securities and Exchange Commission upon request.
10.7	Software License Agreement dated March 2, 2006, between Enertia Software Systems and Concho Resources Inc. (filed as Exhibit 10.6 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.8	Leasehold Acquisition Agreement dated April 1, 2005, by and between Trey Resources, Inc. and COG Oil and Gas LP (filed as Exhibit 10.7 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.9	Transfer of Operating Rights (Sublease) in a Lease for Oil and Gas for Valhalla properties (filed as Exhibit 10.8 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.10	Assignment of Oil and Gas Leases from Caza Energy LLC (filed as Exhibit 10.9 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
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 (filed as Exhibit 10.10 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.12	Business Opportunities Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.11 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).

10.13	Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.12 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.14**	Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.13 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).

Exhibit Number	Exhibit
10.15**	Concho Resources Inc. Summary of Executive Officer Compensation Program (filed as Exhibit 10.15 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.16**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.17**	Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.18**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.19**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.20**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.2 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.21**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.22**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.4 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.23**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and David W. Copeland (filed as Exhibit 10.5 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.24**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.6 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.25**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.7 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.26**	Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.23 to the Company s current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.27**	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.28**	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.29**	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).
10.30	Gas Purchase Contract between COG Oil & Gas LP and Duke Energy Field Services, LP dated November 1, 2006 (filed as Exhibit 10.25 to the Company s current Report on Form S-1 on

	June 6, 2007, and incorporated herein by reference). Confidential treatment of certain provisions of this exhibit has previously been granted by the Securities and Exchange Commission. Omitted material for which confidential treatment has been granted has been filed separately with the Securities and Exchange Commission.
10.31	Letter Agreement between COG Operating LLC and Navajo Refining Company, L.P. dated January 15, 2007 (filed as Exhibit 10.26 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).

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Exhibit Number	Exhibit
10.32	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 (filed as Exhibit 10.27 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.33	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 (filed as Exhibit 10.28 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.34	Third Amendment to Credit Agreement, dated as of May 19, 2008, by and among Concho Resources Inc., certain of its subsidiaries, JPMorgan Chase Bank, N.A. and the other leaders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on May 23, 2008, and incorporated herein by reference).
10.35**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Leach and Beal (filed as Exhibit 10.29 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.36**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Copeland, Kamradt, Thomas and Wright (filed as Exhibit 10.30 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.37**	Form of Amendment to Stock Option Award Agreement with executive officers related to the Pre-Combination Options (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.38**	Form of Amendment to Nonstatutory Stock Option Agreement with executive officers related to the June 2006 Options (filed as Exhibit 10.2 to the Company s current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.39**	Form of Restricted Stock Agreement with executive officers related to the June 2006 Options (filed as Exhibit 10.3 to the Company s current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.40**	Summary of Director Compensation Program (filed as Exhibit 10.41 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.41	Common Stock Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.42	Registration Rights Agreement, dated July 31, 2008, by and between Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
10.43	Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
21.1(a)	Subsidiaries of Concho Resources Inc.
23.1(a)	Consent of Grant Thornton LLP
23.2(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3(a)	Consent of Cawley, Gillespie & Associates, Inc.
31.1(a)	

	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or arrangement.

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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.

/s/ Timothy A. Leach

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

Date: February 27, 2009

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)	February 27, 2009
/s/ STEVEN L. BEAL Steven L. Beal	Director, President and Chief Operating Officer	February 27, 2009
/s/ DARIN G. HOLDERNESS Darin G. Holderness	Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	February 27, 2009
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 27, 2009
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 27, 2009
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, JR.	Director	February 27, 2009
/s/ RAY M. POAGE	Director	February 27, 2009

Ray M. Poage

/s/ A. WELLFORD TABOR	Director	February 27, 2009

A. Wellford Tabor

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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 as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2008. 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Concho Resources Inc. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Concho Resources Inc. s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 27, 2009 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

February 27, 2009
Tulsa, Oklahoma

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CONCHO RESOURCES INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except share and per share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$17,752	$30,424
Accounts receivable, net of allowance for doubtful accounts:		
Oil and gas	48,793	36,735
Joint operations and other	92,833	21,183
Related parties	314	
Derivative instruments	113,149	1,866
Deferred income taxes		13,502
Prepaid costs and other	5,942	4,273
Total current assets	278,783	107,983
Property and equipment, at cost:		
Oil and gas properties, successful efforts method	2,693,574	1,555,018
Accumulated depletion and depreciation	(306,990)	(167,109)
Total oil and gas properties, net	2,386,584	1,387,909
Other property and equipment, net	14,820	7,085
Total property and equipment, net	2,401,404	1,394,994
Deferred loan costs, net	15,701	3,426
Inventory	19,956	1,459
Intangible asset, net operating rights	37,768	
Noncurrent derivative instruments	61,157	
Other assets	434	367
Total assets	$2,815,203	$1,508,229
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$7,462	$14,222
Related parties	312	2,119
Other current liabilities:		
Bank overdrafts	9,434	5,651
Revenue payable	22,286	14,494
Accrued and prepaid drilling costs	154,196	39,276

Derivative instruments	1,866	36,414
Deferred income taxes	37,205	
Current portion of long-term debt		2,000
Other current liabilities	38,057	14,466
Total current liabilities	270,818	128,642
Long-term debt	630,000	325,404
Noncurrent derivative instruments		10,517
Deferred income taxes	573,763	259,070
Asset retirement obligations and other long-term liabilities	15,468	9,198
Commitments and contingencies (Note K)		
Stockholders equity:		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; none issued and outstanding at December 31, 2008 and 2007		
Common stock, $0.001 par value; 300,000,000 authorized; 84,828,824 and 75,832,310 shares issued at December 31, 2008 and 2007, respectively	85	76
Additional paid-in capital	1,009,025	752,380
Notes receivable from employees		(330)
Retained earnings	316,169	37,467
Accumulated other comprehensive loss		(14,195)
Treasury stock, at cost; 3,142 and no shares at December 31, 2008 and 2007, respectively	(125)	
Total stockholders equity	1,325,154	775,398
Total liabilities and stockholders equity	$2,815,203	$1,508,229

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

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CONCHO RESOURCES INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2008	**2007**	**2006**
	(In thousands, except per share amounts)		
Operating revenues:			
Oil sales	$ 390,945	$ 195,596	$ 131,773
Natural gas sales	142,844	98,737	66,517
Total operating revenues	533,789	294,333	198,290
Operating costs and expenses:			
Oil and gas production	91,234	54,267	37,822
Exploration and abandonments	38,468	29,098	5,612
Depreciation, depletion and amortization	123,912	76,779	60,722
Accretion of discount on asset retirement obligations	889	444	287
Impairments of long-lived assets	18,417	7,267	9,891
General and administrative (including non-cash stock-based compensation of $5,223, $3,841 and $9,144 for the years ended December 31, 2008, 2007 and 2006, respectively)	40,776	25,177	21,721
Bad debt expense	2,905		
Contract drilling fees stacked rigs		4,269	
Ineffective portion of cash flow hedges	(1,336)	821	(1,193)
(Gain) loss on derivatives not designated as hedges	(249,870)	20,274	
Total operating costs and expenses	65,395	218,396	134,862
Income from operations	468,394	75,937	63,428
Other income (expense):			
Interest expense	(29,039)	(36,042)	(30,567)
Other, net	1,432	1,484	1,186
Total other expense	(27,607)	(34,558)	(29,381)
Income before income taxes	440,787	41,379	34,047
Income tax expense	(162,085)	(16,019)	(14,379)
Net income	278,702	25,360	19,668
Preferred stock dividends		(45)	(1,244)
Effect of induced conversion of preferred stock			11,601
Net income applicable to common shareholders	$ 278,702	$ 25,315	$ 30,025
Basic earnings per share:			

Net income per share	$ 3.52	$ 0.39	$ 0.63
Weighted average shares used in basic earnings per share	79,206	64,316	47,287
Diluted earnings per share:			
Net income per share	$ 3.46	$ 0.38	$ 0.59
Weighted average shares used in diluted earnings per share	80,587	66,309	50,729

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

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CONCHO RESOURCES INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	6% Series A Preferred Stock Shares	Amount	Common Stock Shares	Amount	Additional Paid-in Capital	Notes Receivable from Officers and Employees	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Amount	St
						(In thousands)					
AT R 31, 2005	12,959	$ 130	8,142	$ 8	$ 135,876	$ (9,012)	$ (6,272)	$ (11,060)		$	$
ve income:											
							19,668				
ge gains, $4,200								7,736			
nt losses arnings, net 2,030								3,738			
ehensive											
ubscribed	4,518	45	2,259	2	45,329	(3,158)					
ommon			578	1	577						
f preferred	(17,477)	(175)	13,106	13	162						
ommon uisition			34,795	35	384,301						
n for ck			214		1,044						
of restricted			(1)								
n for stock					7,125						
n on nits					975						
rest officer e notes						(688)					
preferred ds							(1,244)				

AT R 31, 2006	59,093	59	575,389	(12,858)	12,152	414
ve income:						
					25,360	
ge losses, of $13,204						(20,579)
nt losses arnings, net 3,830						5,970
ehensive						
n for ck	138		1,378			
of restricted	(2)					
n for stock			2,463			
of certain tock o 409A	83		(192)			
ommon uisition	54		650			
from initial offering	16,466	17	172,692			
m notes officers and				12,830		
rest officer e notes				(302)		
preferred nds					(45)	
AT R 31, 2007	75,832	76	752,380	(330)	37,467	(14,195)
ve income:						
					278,702	
ge losses, of $3,121						(4,864)
nt losses arnings, net 12,228						19,059
ehensive						
ommon	8,303	8	242,418			

s exercised	612	1	5,390					
n for ck	128		2,122					
of restricted	(46)							
n for stock			3,101					
enefits ck-based n			3,614					
m notes employees				333				
rest tes				(3)				
reasury						3	(125)	
AT R 31, 2008	$ 84,829	$ 85	$ 1,009,025	$	$ 316,169	$ 3	$ (125)	$

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

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CONCHO RESOURCES INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 278,702	$ 25,360	$ 19,668
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	123,912	76,779	60,722
Impairments of long-lived assets	18,417	7,267	9,891
Accretion of discount on asset retirement obligations	889	444	287
Exploration expense, including dry holes	35,328	25,009	3,387
Non-cash compensation expense	5,223	3,841	9,144
Deferred income taxes	153,484	13,716	12,618
Gain on sale of assets	(777)	(368)	(3)
Ineffective portion of cash flow hedges	(1,336)	821	(1,193)
(Gain) loss on derivatives not designated as hedges	(249,870)	20,274	
Dedesignated cash flow hedges reclassified from accumulated other comprehensive income (loss)	696	(1,103)	
Other non-cash items	6,517	3,376	1,150
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	42,514	(5,759)	(27,683)
Prepaid costs and other	(5,542)	(169)	(2,162)
Inventory	(16,819)	(150)	(291)
Accounts payable	(25,234)	(3,493)	13,853
Revenue payable	7,074	4,593	2,372
Other current liabilities	18,219	(669)	10,421
Net cash provided by operating activities	391,397	169,769	112,181
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on oil and gas properties	(347,702)	(162,378)	(182,389)
Acquisition of oil and gas properties, businesses and other assets	(584,220)	(255)	(413,229)
Additions to other property and equipment	(8,808)	(2,813)	(1,234)
Proceeds from the sale of oil and gas properties and other assets	1,034	3,278	
Settlements received (paid) on derivatives not designated as hedges	(6,354)	1,815	
Net cash used in investing activities	(946,050)	(160,353)	(596,852)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of long-term debt	767,800	300,200	664,993
Payments of long-term debt	(465,700)	(468,800)	(241,493)
Exercise of stock options	5,391		
Excess tax benefit from stock-based compensation	3,614		

Net proceeds from issuance of common stock		242,426		172,709		61,178
Payments of preferred stock dividends				(132)		(2,567)
Proceeds from repayment of officer and employee notes		333		12,830		
Payments for loan origination costs		(15,541)		(2,572)		(5,500)
Purchase of treasury stock		(125)				
Bank overdrafts		3,783		5,651		
Net cash provided by financing activities		541,981		19,886		476,611
Net increase (decrease) in cash and cash equivalents		(12,672)		29,302		(8,060)
Cash and cash equivalents at beginning of period		30,424		1,122		9,182
Cash and cash equivalents at end of period	$	17,752	$	30,424	$	1,122
SUPPLEMENTAL CASH FLOWS:						
Cash paid for interest and fees, net of $1,233, $2,647 and $2,129 capitalized interest	$	27,747	$	41,036	$	23,882
Cash paid for income taxes	$	11,304	$	2,050	$	1,725
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	$	206,497	$	(444)	$	227,735
Issuance of notes receivable in connection with capital options	$		$		$	3,158

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

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CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2008, 2007 and 2006

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 in Southeastern New Mexico from the Chase Group (the Chase Group Properties) and issued shares of Resources 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 members of Resources management team and private equity investors. CEHC commenced substantial oil and gas operations in December 2004 upon its acquisition of oil and gas properties located in Southeastern 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 collectively referred to herein as the Company.

In the Combination, CEHC s shareholders received 23,767,691 shares of common stock of the Company 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 F. In addition, the Chase Group transferred the Chase Group Properties to the Company in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of the Company s common stock. In connection with the Company s initial public offering and secondary public offering (see Note F), the Chase Group sold a total of 18,638,014 shares of the Company s common stock. At December 31, 2008 and December 31, 2007, the Chase Group owned approximately 9 percent and 21 percent, respectively, of the total outstanding common stock 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 Southeastern New Mexico and West Texas.

Note B. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company 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 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

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 counterparty 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 an allowance for doubtful accounts of approximately $2.9 million and none at December 31, 2008 and 2007, respectively, and the Company did not write off any receivables against the allowance for doubtful accounts in 2008, 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, on a weighted average cost basis.

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 $15.7 million and $3.4 million, net of accumulated amortization of $3.3 million and $3.6 million, at December 31, 2008 and December 31, 2007, respectively.

Future amortization expense of deferred loan costs at December 31, 2008 is as follows:

	Total (In thousands)
2009	$ 3,426
2010	3,426
2011	3,426
2012	3,426
2013	1,997
Total	$ 15,701

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 using the unit-of-production method based on proved reserves. The depletion of capitalized exploratory drilling and development costs is based on the unit-of-production method using proved developed reserves on a field basis.

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company generally does not carry the costs of drilling an exploratory well as an asset in its Consolidated Balance Sheets for more than one year following the completion of drilling unless the exploratory well finds oil and gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well.

(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project s feasibility is not contingent upon price improvements or advances in technology, but rather the Company s ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company s assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is charged to exploration and abandonments expense. See Note C for additional information regarding the Company s suspended exploratory well costs.

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. 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 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, 2008 and 2007 the Company had excluded $27.8 million and $19.0 million, respectively, of capitalized costs from depletion and had capitalized interest of $1.2 million, $2.6 million and $2.1 million, during 2008, 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 or by individual well for those wells not constituting part of an amortization base. For each property 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 $18.4 million, $7.3 million and $9.9 million during the years ended December 31, 2008, 2007 and 2006, 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, 2008, 2007 and 2006, the Company recognized expense of $31.6 million, $3.1 million and $0.2 million, respectively, related to abandoned prospects, which is included in exploration and abandonments in the accompanying consolidated statements of operations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other property and equipment. Other capital assets include buildings, vehicles, computer equipment and software, telecommunications equipment, leasehold improvements 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 two to 15 years.

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition, see Note D. The gross operating rights of approximately $38.4 million, which have no residual value, are amortized over the estimated economic life of approximately 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. Amortization expense for the year ended December 31, 2008 was approximately $0.6 million. The following table reflects the estimated aggregate amortization expense for each of the periods presented below:

	(In Thousands)
2009	$ 1,536
2010	1,536
2011	1,536
2012	1,536
2013	1,536
Thereafter	30,088
Total	$ 37,768

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 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 material liabilities of this nature existed at December 31, 2008 or 2007.

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.

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The following table reflects the Company s gas imbalance positions at December 31, 2008 and 2007 as well as amounts reflected in oil and gas production expense for the years ended December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	(Dollars in thousands)	
Gas imbalance liability (included in asset retirement obligations and other long-term liabilities)	$ 472	$ 621
Overtake position (Mcf)	85,698	96,215
Gas imbalance receivable (included in other assets)	$ 406	$ 367
Undertake position (Mcf)	90,321	81,569

	Years Ended December 31, 2008	Years Ended December 31, 2007
Value of net undertake arising during the year (reducing oil and gas production expense)	$ 189	$ 14
Net undertake position arising during the year (Mcf)	19,269	4,264

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 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 (AOCI) 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 and measures 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 AOCI 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.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

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 $4.9 million, $1.1 million and $0.8 million for the years ended December 31, 2008, 2007 and 2006, 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.

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 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.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2008 presentation. These reclassifications had no impact on net income, total stockholders equity or cash flows.

Recent accounting pronouncements. 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 became 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 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

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 has not had 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 did not adopt EITF Issue 06-11 until the required effective date of January 1, 2008. The adoption of EITF Issue 06-11 has not had a significant effect on the Company s 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. SFAS No. 141(R) 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 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, 2008, which will be the Company s fiscal year 2009. Based upon the Company s December 31, 2008 consolidated balance sheet, the statement would have no impact.

In December 2007, the SEC issued Staff Accounting Bulletin (SAB) No. 110, *Share-Based Payment* (SAB No. 110). SAB No. 110 amends SAB No. 107, *Share-Based Payment*, and allows for the continued use, under certain circumstances, of the simplified method in developing an estimate of the expected term on stock options accounted for under SFAS No. 123R, *Share-Based Payment (revised 2004).* SAB No. 110 is effective for stock options granted after

December 31, 2007. The Company continued to use the simplified method in developing an estimate of the expected term on stock options granted in 2008. The Company does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time the Company s shares of common stock have been publicly traded.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities*, which amends and expands the disclosure requirements of SFAS No. 133 to provide an enhanced understanding of an entity s use of derivative instruments, how they are accounted for under SFAS No. 133 and their

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effect on the entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective as of January 1, 2009. The Company is currently evaluating the impact on its consolidated financial statements of adopting SFAS No. 161.

In April 2008, the FASB issued FASB Staff Position (FSP) No. SFAS 142-3, *Determination of the Useful Life of Intangible Assets* (FSP SFAS No. 142-3). FSP SFAS No. 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). The intent of FSP SFAS No. 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R and other applicable accounting literature. FSP SFAS No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. The Company is currently evaluating the potential impact, if any, of FSP SFAS No. 142-3 on its financial statements.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*, which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. This statement is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. The Company does not expect the adoption of SFAS No. 162 to have an impact on its consolidated financial statements.

In June 2008, the FASB issued Staff Position No. EITF 03-6-1 *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 was effective for us on January 1, 2009 and all prior-period EPS data (including any amounts related to interim periods, summaries of earnings and selected financial data) will be adjusted retroactively to conform to its provisions. Early application of FSP EITF 03-6-1 is not permitted. Although restricted stock awards meet this definition, the Company does not expect the application of FSP EITF 03-6-1 to have a significant impact on its reported earnings per share.

In October 2008, the FASB issued FSP No. SFAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active*. FSP No. SFAS 157-3 clarifies the application of SFAS No. 157 as it relates to the valuation of financial assets in a market that is not active for those financial assets. This FSP is effective immediately and includes those periods for which financial statements have not been issued. The Company currently does not have any financial assets that are valued using inactive markets, and as a result, the Company is not impacted by the issuance of FSP No. SFAS 157-3.

Recent developments in reserve reporting. The United States Securities and Exchange Commission (SEC) recently approved new disclosure rules that allow oil and natural gas companies to more accurately report their assets in terms of volumes and values that investors can understand and use to make informed decisions. The new reporting requirement is effective on December 15, 2009. The new disclosure requirements include provisions that:

permit the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes;

allow companies to disclose in SEC filed documents their probable and possible reserves to investors (currently, the SEC rules limit disclosure to only proved reserves);

require companies to report the independence and qualifications of a reserves preparer or auditor;

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file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit; and

report oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices.

The Company is currently evaluating the impact these new reserve reporting requirements will have on its consolidated financial statements.

Note C. *Exploratory well costs*

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in unproved properties in the Consolidated Balance Sheets. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company s capitalized exploratory well activity during each of the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31, 2008	2007	2006
	(In thousands)		
Beginning capitalized exploratory well costs	$ 21,056	$ 26,503	$ 4,370
Additions to exploratory well costs pending the determination of proved reserves	25,621	97,368	25,170
Reclassifications due to determination of proved reserves	(18,327)	(95,869)	(2,759)
Exploratory well costs charged to expense	(2,797)	(6,946)	(278)
Ending capitalized exploratory well costs	$ 25,553	$ 21,056	$ 26,503

The following table provides an aging at December 31, 2008 and 2007 of capitalized exploratory well costs based on the date the drilling was completed:

	December 31, 2008	2007
	(In thousands)	
Wells in drilling progress	$ 7,765	$ 4,199
Capitalized exploratory well costs that have been capitalized for a period of one year or less	17,788	16,857

Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Total capitalized exploratory well costs	$ 25,553	$ 21,056

At December 31, 2008, the Company had 18 gross exploratory wells either drilling or waiting on results from completion. There are 4 wells in the New Mexico Permian area, 9 wells in the Texas Permian area, 3 wells in the Arkoma Basin in Arkansas and 2 wells in the Williston Basin of North Dakota.

Note D. ***Acquisition and business combination***

Henry Entities acquisition. On July 31, 2008, the Company closed our acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (which we refer to as Henry or the Henry Entities) and additional non-operated interests in oil and gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and gas properties from persons

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affiliated with the Henry Entities. The assets acquired in the Henry Entities acquisition are referred to as the Henry Properties. The Company paid $584.1 million in cash for the Henry Properties acquisition.

The cash paid for the Henry Properties acquisition was funded with (i) borrowings under the Company s credit facility, see Note J, and (ii) proceeds from a private placement of approximately 8.3 million shares of the Company s common stock, see Note F.

The Henry Properties acquisition is being accounted for using the purchase method of accounting for business combinations. Under the purchase method of accounting, the Company recorded the Henry Properties assets and liabilities at fair value. The purchase price of the acquired Henry Properties net assets is based on the total value of the cash consideration. The initial purchase price allocation is preliminary and subject to adjustment. Any future adjustments to the allocation of the total purchase price are not anticipated to be material to the Company s consolidated financial statements.

The following tables represent the preliminary allocation of the total purchase price of the Henry Properties to the acquired assets and liabilities of the Henry Properties and the consideration paid for the Henry Properties. The allocation represents the fair values assigned to each of the assets acquired and liabilities assumed:

		(In thousands)
Fair value of Henry Properties net assets:		
Current assets, net of cash acquired of $19,049(a)	$	86,321
Proved oil and gas properties		595,005
Unproved oil and gas properties		233,199
Other long-term assets		6,977
Intangible assets operating rights		38,409
Total assets acquired		959,911
Current liabilities		(113,729)
Asset retirement obligations and other long-term liabilities		(7,529)
Noncurrent derivative liabilities		(39,037)
Deferred tax liability		(215,475)
Total liabilities assumed		(375,770)
Net purchase price	$	584,141
Consideration paid for Henry Properties net assets:		
Cash consideration paid, net of cash acquired of $19,049	$	578,491
Acquisition costs(b)		5,650
Total purchase price	$	584,141

(a) Includes a deferred tax asset of approximately $9.0 million.

(b) Estimated acquisition costs include legal and accounting fees, advisory fees and other acquisition-related costs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following unaudited pro forma combined condensed financial data for the years ended December 31, 2008 and 2007 was derived from the historical financial statements of the Company and Henry Properties giving effect to the acquisition as if it had occurred on January 1 of each period. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Henry Properties acquisition taken place as of the dates indicated and is not intended to be a projection of future results.

	Years Ended December 31,	
	2008	2007
	(In thousands, except per share data)	
Operating revenues	$ 629,214	$ 389,758
Net income (loss) applicable to common shareholders	$ 257,540	$ (7,471)
Earnings (loss) per common share:		
Basic	$ 2.94	$ (0.10)
Diluted	$ 2.90	$ (0.10)

Chase Group combination. On February 27, 2006, the Company closed a Combination Agreement with the Chase Group whereby ownership in oil and gas properties and non-producing leasehold acreage in Southeastern New Mexico (the Chase Group Properties) were combined with the properties previously owned by CEHC. The Chase Group received cash in the aggregate amount of $409 million and 34,794,638 shares of Resources common stock valued at $384 million for an aggregate purchase price of $793 million including transaction costs. The results of the Chase Group Properties have been included in the consolidated financial statements since that date.

Note E. ***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, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Asset retirement obligations, beginning of period	$ 9,418	$ 8,700	$ 1,120

Liabilities incurred from new wells	1,197	471	1,288
Liabilities assumed in acquisitions	7,062		6,155
Accretion expense	889	444	287
Liabilities settled upon plugging and abandoning wells		(26)	
Revision of estimates	(1,757)	(171)	(150)
Asset retirement obligations, end of period	$ 16,809	$ 9,418	$ 8,700

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

Common stock private placement. On June 5, 2008, the Company entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of the Company s common stock in a

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

private placement (the Private Placement) contemporaneous with the closing of the Henry Properties acquisition. On July 31, 2008, the Company issued 8,302,894 shares of its common stock at $30.11 per share. The Private Placement resulted in net proceeds of approximately $242.4 million to the Company, after payment of approximately $7.6 million for the fee paid to the placement agent.

In connection with the Private Placement, the Company entered into a registration rights agreement with the investors. On October 24, 2008, pursuant to the registration rights agreement, the Company filed a registration statement to register the shares of common stock issued in the Private Placement.

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 of its common stock in the IPO and certain shareholders, including its executive officers and certain members of the Chase Group, sold 7,554,256 shares of the Company s common stock 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 the Company s 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 to reduce bank debt.

Secondary public offering. On December 19, 2007, the Company completed a secondary public offering of 11,845,000 shares of the Company s common stock, which was sold by certain of the Company s stockholders, including certain members of the Chase group. The Chase Group sold 10,194,732 shares of the Company s common stock in the aggregate and certain other stockholders of the Company sold 1,650,268 shares of the Company s common stock in the aggregate, including one of the Company s executive officers who sold 45,000 shares of the Company s common stock. Chase Oil Corporation granted the underwriters an option to purchase up to 1,776,615 additional shares of the Company s common stock to cover over-allotments, which was fully exercised on December 19, 2007. The Company did not receive any proceeds from the sale of the Company s common stock in this secondary offering.

Treasury stock. On June 12, 2008, the restrictions on certain restricted stock awards issued to five of the Company s executive officers lapsed. Immediately upon the lapse of restrictions, these executive officers became liable for certain federal income taxes on the value of such shares. In accordance with the Company s 2006 Stock Incentive Plan and the applicable restricted stock award agreements, four of such officers elected to deliver shares of the Company s common stock to the Company to satisfy such tax liability, and the Company acquired 3,142 shares to be held as treasury stock in the approximate amount of $125,000.

Equity commitments. Pursuant to a stock purchase agreement (the Stock Purchase Agreement) entered into on August 13, 2004, CEHC 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 approximately $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 CEHC, the Private Investors and the Officers, certain employees and other officers of the Company entered into separate subscription agreements with the Company. The officers and employees equity purchases were paid for in a combination of cash and the issuance of notes payable to the

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 Company s officers and employees subject to the Purchase Notes are accounted for as the issuance of options (Bundled Capital Options for the Officers and Capital Options for employees) on the dates that the various subscription agreements were signed and the purchase commitments were made.

Capital calls. From inception of CEHC through February 23, 2006, the Private Investors purchased 16,113,170 Preferred Units for $161.1 million in cash; the Company s officers 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, and certain employees purchased 425,221 Preferred Units for $1.0 million in cash and Purchase Notes totaling $3.8 million.

6% Series A preferred stock. Preferred stock dividends were generally paid on the anniversary of date of issuance of preferred stock as a part of the Preferred Units. There were no dividend payments made during the year ended December 31, 2008, because there was no outstanding preferred stock. Preferred stock dividends of approximately $132,000 and $2.6 million were paid during the years ended December 31, 2007 and 2006, respectively. As discussed in Note A and below, the majority of the CEHC preferred stock was converted into Resources common stock in the Combination. Final dividend payments on converted CEHC 6% Series A Preferred Stock were made in March 2006.

Dividend payments continued to be made through April 16, 2007 to the eighteen employee shareholders that did not convert their shares of CEHC preferred stock to Resources common stock in the Combination. 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 date of the Combination.

Purchase Notes. On April 23, 2007, the Company s officers repaid their Purchase Notes in full, including principal of $9.4 million and accrued interest of $1.0 million in the aggregate. 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 was formerly an executive officer.

At December 31, 2008, all Purchase Notes from all employees had been paid in full. As such, the repayment of the Purchase Notes represent the full exercise of the options on the Capital Options held by certain employees. 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.

CONCHO RESOURCES INC.

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 and 2006:

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

The following table summarizes the Capital Options activity for the years ended December 31, 2008, 2007 and 2006:

	Number of Capital Options	Weighted Average Exercise Price
Outstanding at December 31, 2005	482,500	$ 9.74
$15 Capital Options granted	16,000	$ 12.13
Cancelled/forfeited	(73,279)	$ 9.81
Outstanding at December 31, 2006	425,221	$ 9.81
$10 Capital Options exercised	(270,828)	$ 8.97
$15 Capital Options exercised	(116,008)	$ 12.26
Outstanding at December 31, 2007	38,385	$ 8.34
$10 Capital Options exercised	(38,385)	$ 8.34
Outstanding at December 31, 2008		$
Vested outstanding at:		
December 31, 2006	425,221	$ 9.81
December 31, 2007	38,385	$ 8.34

December 31, 2008	$

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

		Capital Options Outstanding, Vested and Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value
Vested Capital Options Outstanding and Exercisable at December 31, 2007:					
Exercise price	$ 10.00	38,385	2.52 years	$ 8.34	$ 562,000

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CONCHO RESOURCES INC.

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 year ended December 31, 2006. There was no stock-based compensation for Capital Options in 2008 and 2007.

Stock-based compensation expense from Capital Options	$ 975,000
Bundled Capital Options:	
Stock-based compensation expense	$ 508,000
Options vesting during period	242,000
Weighted average grant date fair value per option	$ 2.10
Capital Options:	
Stock-based compensation expense	$ 467,000
Options vesting during period	119,799
Weighted average grant date fair value per option	$ 3.90

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, the majority of the shares outstanding of CEHC preferred stock and outstanding shares of CEHC common stock were converted to shares of the Company s 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 the Company s 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 date of the Combination. 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 and the conversion of CEHC preferred stock into the Company s common stock at the ratio of 0.75:1, the CEHC Bundled Capital Options were converted into the Company s Bundled Capital Options and CEHC Capital Options were converted into the Company s Capital Options. The Company s Capital Options are considered to be exercisable for 1.25 shares of the Company s 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.

Note G. ***Incentive plans***

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees and maintains certain other acquired plans. The Company matches 100 percent of employee contributions, not to exceed 6 percent of the employee s annual salary. The Company contributions to the plans for the years ended December 31, 2008, 2007 and 2006 were approximately $1.2 million, $419,000, and

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$321,000, respectively. The increase in contributions for the year ended December 31, 2008, were primarily attributable to the addition of employees due to the Henry Entities acquisition on July 31, 2008.

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. The following table shows the number of awards available under the Company s Plan at December 31, 2008:

	Number of Common Shares
Approved and authorized awards	5,850,000
Stock option grants, net of forfeitures	(3,343,684)
Restricted stock grants, net of forfeitures	(512,809)
Awards available for future grant	1,993,507

Restricted stock awards. 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, 2008, 2007 and 2006 is presented below:

	Number of Restricted Shares	Grant Date Fair Value Per Share
Restricted stock:		
Outstanding at January 1, 2006		
Shares granted	213,584	$ 15.40
Shares cancelled/forteited	(1,368)	
Lapse of restrictions		
Outstanding at December 31, 2006	212,216	
Shares granted	220,995	$ 9.22
Shares cancelled/forteited	(1,662)	
Lapse of restrictions	(60,000)	
Outstanding at December 31, 2007	371,549	
Shares granted	128,001	$ 32.13
Shares cancelled/forteited	(46,741)	
Lapse of restrictions	(45,458)	

Outstanding at December 31, 2008	407,351

A summary of the impact on the consolidated statements of operations for the Company s restricted stock awards during the years ended December 31, 2008, 2007 and 2006 is presented below:

	Years Ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Stock-based compensation expense related to restricted stock	$ 2,122	$ 1,378	$ 1,044
Income tax benefit related to restricted stock	$ 808	$ 533	$ 407
Deductions in current taxable income related to restricted stock	$ 1,234	$	$

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Stock option awards. The stock options granted from August 13, 2004 through February 27, 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 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 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	
	Number of Units(a)	Weighted Average Price

Outstanding at beginning of period	1,365,075	$	10.32
Options granted	514,267	$	10.68
Options forfeited		$	
Options exercised		$	
Outstanding at end of period	1,879,342	$	10.42
Exercisable at end of period	1,562,770	$	10.51

(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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Also in conjunction with the Combination described in Note A and Note D 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 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
	1,879,342				2,349,113

A summary of the Company s stock option activity under the Plan, for the years ended December 31, 2008 and 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:

	Years Ended December 31,						February 27, 2006 through December 31, 2006		
	2008			2007					
	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price	Number of Options		Weighted Average Exercise Price
Stock options:									
Outstanding at beginning of period	3,011,722	$	9.71	2,797,997	$	8.93	2,349,113	$	8.34
Options granted	607,555	$	23.54	215,000	$	12.85	450,000	$	12.00
Options forfeited	(275,593)	$	14.96	(1,275)	$	8.00	(1,116)	$	10.88
Options exercised	(612,360)	$	8.80		$			$	
Outstanding at end of period	2,731,324	$	12.46	3,011,722	$	9.71	2,797,997	$	8.93
Vested at end of period	1,567,389	$	9.18	2,063,499	$	8.79	1,952,274	$	8.40

Exercisable at end of period	517,019	$	11.16	508,462	$	10.58	1,952,274	$	8.40

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes information about the Company s vested stock options outstanding and exercisable at December 31, 2008, 2007 and 2006:

		Number Vested and Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value (In thousands)
Vested options:					
December 31, 2008:					
Exercise price	$ 8.00	1,232,647	2.58 years	$ 8.00	$ 18,268
Exercise price	$ 12.00	143,492	4.99 years	$ 12.00	1,553
Exercise price	$ 14.68	191,250	7.78 years	$ 14.68	1,556
		1,567,389		$ 9.18	$ 21,377
Exercisable options:					
December 31, 2008:					
Exercise price	$ 8.00	236,227	5.62 years	$ 8.00	$ 3,501
Exercise price	$ 12.00	89,542	6.78 years	$ 12.00	969
Exercise price	$ 14.68	191,250	7.78 years	$ 14.68	1,556
		517,019		$ 11.16	$ 6,026
Vested options:					
December 31, 2007:					
Exercise price	$ 8.00	1,753,819	3.15 years	$ 8.00	$ 22,116
Exercise price	$ 12.00	197,180	5.72 years	$ 12.00	1,698
Exercise price	$ 15.40	112,500	8.45 years	$ 15.40	586
		2,063,499		$ 10.58	$ 24,400
Exercisable options:					
December 31, 2007:					
Exercise price	$ 8.00	275,685	6.62 years	$ 8.00	$ 3,476
Exercise price	$ 12.00	120,277	7.78 years	$ 12.00	1,036
Exercise price	$ 15.40	112,500	8.45 years	$ 15.40	586
		508,462		$ 10.58	$ 5,098

Vested and exercisable options:					
December 31, 2006:					
Exercise price	$ 8.00	1,755,094	8.47 years	$ 8.00	$ 15,099
Exercise price	$ 12.00	197,180	8.86 years	$ 12.00	$ 769
		1,952,274		$ 8.40	$ 15,868

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes information about stock-based compensation for options which is recognized in general and administrative expense in the accompanying consolidated statement of operations for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31, 2008	2007	2006
	(In thousands)		
Grant date fair value for awards during the period:			
Time Vesting options(a)	$ 580	$ 87	$ 1,931
Performance Vesting options:			
Officers(b)			531
Non-officers(c)			142
Stock option grants under the Plan(d)	5,675	1,921	3,555
Total	$ 6,255	$ 2,008	$ 6,159
Stock-based compensation expense from stock options:			
Time Vesting options(a)	$ 181	$ 17	$ 5,085
Performance Vesting options:			
Officers(b)	253	602	511
Non-officers(c)			505
Stock option grants under the Plan(d)	2,667	1,844	1,024
Total	$ 3,101	$ 2,463	$ 7,125
Income taxes and other information:			
Income tax benefit related to stock options	$ 1,990	$ 953	$ 2,779
Deductions in current taxable income related to stock options exercised	$ 10,756	$	$

(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 three or 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 Code Section 409A (defined later) option modification.

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 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:

	2008	**2007**	**2006**
Risk-free interest rate	3.18%	4.47%	4.81%
Expected term (years)	6.21	6.25	2.87
Expected volatility	38.88%	37.33%	37.12%
Expected dividend yield			

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 percent increments over a four year period beginning in 2008 and continuing through 2011 or upon the occurrence of certain specified events. Employees 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 $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 modifications of approximately $0.8 million will be recorded during the period from November 8, 2007 to December 31, 2007 and during the years ending December 31, 2008, 2009 and 2010.

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that are outstanding at December 31, 2008:

	Restricted Stock	Stock Options	Total
		(In thousands)	
2009	$ 2,470	$ 2,701	$ 5,171
2010	1,393	1,242	2,635
2011	475	466	941

2012	40	55	95
Total	$ 4,378	$ 4,464	$ 8,842

Note H. ***Disclosures about fair value of financial instruments***

The Company adopted SFAS No. 157, *Fair Value Measurements*, (SFAS No. 157) effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

***Level 1*:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

***Level 2*:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, investments and interest rate swaps. The Company s valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company utilizes our counterparties valuations to assess the reasonableness of our prices and valuation techniques.

***Level 3*:** Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). Level 3 instruments primarily include derivative instruments, such as basis swaps, commodity price collars and floors, as well as investments. The Company s valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although the Company utilizes our counterparties valuations to assess the reasonableness of our prices and valuation techniques, the Company does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

The following represents information about the estimated fair values of the Company s 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) approximate fair value because the instruments bear interest at variable market rates.

Derivative instruments. The fair value of the derivative instruments are estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes the valuation of the Company s financial instruments by SFAS No. 157 pricing levels at December 31, 2008:

	Fair value measurements using			
	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total carrying value at December 31, 2008
	(In thousands)			
Commodity derivative price swap contracts	$	$ 124,641	$	$ 124,641
Commodity derivative basis swap contracts		(680)		(680)
Interest rate derivative swap contracts		(1,083)		(1,083)
Commodity derivative price collar contracts			49,562	49,562
Total financial assets (liabilities)	$	$ 122,878	$ 49,562	$ 172,440

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	(In Thousands)
Balance at January 1, 2008	$ 1,866
Realized and unrealized gains	49,122
Purchases, issuances, and settlements	(1,426)
Balance at December 31, 2008	$ 49,562
Total gains for the period included in earnings attributable to the change in unrealized gains relating to assets still held at the reporting date	$ 47,696

For additional information on the Company s derivative instruments see Note I.

Note I. ***Derivative financial instruments***

The Company uses financial derivative contracts to manage exposures to commodity price and interest rate. Commodity hedges are used to (i) reduce the effect of the volatility of price changes on the natural gas and crude oil the Company produces and sells, (ii) support the Company s annual capital budget and expenditure plans and (iii) support the economics associated with acquisitions. Interest rate hedges are used to hedge our mitigate the cash flow risk associated with rising interest rates. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company also may enter physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the financial statements.

Currently, the Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects the changes in the fair value of its derivative instruments in the statements of operations.

A key requirement for designation of derivative instruments to qualify for hedge accounting 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. For all quarters ended prior to July 1, 2007, prices received for

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the Company s natural gas were highly correlated with the Inside FERC El Paso Natural Gas index (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 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 hedge accounting prospectively 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. 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.

During the three months ended 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 above paragraph. These contracts are referred to as dedesignated hedges.

Therefore, June 30, 2007, was considered the last date the Company s natural gas hedges were highly effective, and the Company discontinued hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges are recorded each period to earnings. Effective portions of dedesignated hedges, previously recorded in AOCI at June 30, 2007, remain in AOCI and are being reclassified into earnings under natural gas revenues, during the periods which the hedged forecasted transaction affects earnings.

2008 commodity derivative contracts. During the year ended December 31, 2008, the Company entered into additional commodity derivative contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts at December 31, 2008:

	Aggregate Remaining Volume	**Daily Volume**	**Index Price**	**Remaining Contract Period**
Crude oil (volumes in Bbls):				
Price collar	768,000	2,104	$ 120.00 - $134.60(a)	1/1/09-12/31/09
Price swap	292,000	800	$ 98.35(a)	1/1/09-12/31/09
Price swap	348,000	953	$ 125.10(a)	1/1/09-12/31/09
Price swap	240,000	658	$ 128.80(a)	1/1/10-12/31/10
Price swap	336,000	921	$ 128.66(a)	1/1/11-12/31/11
Price swap	504,000	1,377	$ 127.80(a)	1/1/12-12/31/12
Natural gas (volumes in MMBtus):				
Price swap	1,825,000	5,000	$ 8.44(b)	1/1/09-12/31/09

Index basis swap	6,022,500	16,500	$	1.08(c)	1/1/09-12/31/09

(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) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Commodity derivative contracts assumed in the Henry Entities acquisition. As part of the Henry Entities acquisition, the Company assumed the following commodity derivative contracts on July 31, 2008. The following table summarizes information about the remaining portion of these assumed derivative contracts at December 31, 2008:

	Aggregate Remaining Volume	Daily Volume	Index Price	Remaining Contract Period
Crude oil (volumes in Bbls):				
Price swap	443,491	1,215	$ 73.59(a)	1/1/09 - 12/31/09
Price swap	401,746	1,101	$ 72.03(a)	1/1/10 - 12/31/10
Price swap	221,746	608	$ 68.92(a)	1/1/11 - 12/31/11

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

2008 interest rate derivative contracts. During 2008, the Company entered into interest rate derivative contracts to hedge a portion of its future interest rate exposure. The Company hedged its LIBOR interest rate on the Company s bank debt by fixing the rate at 1.90 percent for three years beginning in May of 2009 on $300 million of the Company s bank debt. The interest rate derivative contracts were not designated as cash flow hedges.

The following table sets forth the Company s outstanding derivative contracts at December 31, 2008:

		Fair Value Asset (Liability) (In thousands)	Aggregate Remaining Volume / Notional Amount	Daily Volume	Index Price / Rate	Remaining Contract Period
Crude oil (volumes in Bbls):						
Price collar	$	49,562	768,000	2,104	$120.00 - $134.60(a)	1/1/09 - 12/31/09
Price swap		58,269	1,813,491	4,968	$87.16(a)(c)	1/1/09 - 12/31/09
Price swap		17,948	641,746	1,758	$93.26(a)(c)	1/1/10 - 12/31/10
Price swap		18,191	557,746	1,528	$104.91(a)(c)	1/1/11 - 12/31/11
Price swap		24,339	504,000	1,377	$127.80(a)	1/1/12 - 12/31/12

Natural gas (volumes in MMBtus):					
Price swap	5,894	1,825,000	5,000	$8.44(b)	1/1/09 - 12/31/09
Basis swap	(680)	6,022,500	16,500	$1.08(d)	1/1/09 - 12/31/09
Interest rate (notional amount in dollars):					
Rate swap	(1,083)	$ 300,000,000		1.90%(e)	5/1/09 - 4/30/12
Net asset	$ 172,440				

(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) Prices represent weighted average prices.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(d) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

(e) The index rate is based on the one-month LIBOR.

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 that qualified for cash flow hedge accounting. The following table summarizes the gains and losses reported in earnings related to the commodity and interest rate derivative instruments and the net change in AOCI*:*

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Increase (decrease) in oil and gas revenue from derivative activity:			
Cash payments on cash flow hedges in oil sales	$ (30,591)	$ (11,091)	$ (7,000)
Cash receipts from cash flow hedges in gas sales		188	1,232
Dedesignated cash flow hedges reclassified from AOCI in gas sales	(696)	1,103	
Total decrease in oil and gas revenue from derivative activity	$ (31,287)	$ (9,800)	$ (5,768)
Gain (loss) on derivatives not designated as hedges:			
Mark-to-market gain (loss):			
Commodity derivatives	$ 257,307	$ (22,089)	$
Interest rate derivatives	(1,083)		
Cash (payments) receipts on derivatives not designated as hedges:			
Commodity derivatives	(6,354)	1,815	
Interest rate derivatives			
Total gain (loss) on derivatives not designated as hedges	$ 249,870	$ (20,274)	$
Gain (loss) from ineffective portion of cash flow hedges:	$ 1,336	$ (821)	$ 1,193
Accumulated other comprehensive income (loss):			
Cash flow hedges:			
Mark-to-market gain (loss) of cash flow hedges	$ (7,985)	$ (33,783)	$ 11,936
Reclassification adjustment of losses to earnings	30,591	10,903	5,768
Net AOCI upon dedesignation at June 30, 2007		(407)	
Net change, before income taxes	22,606	(23,287)	17,704
Income tax effect	(8,835)	9,102	(6,230)
Net change, net of income taxes	$ 13,771	$ (14,185)	$ 11,474

Dedesignated cash flow hedges:						
Net AOCI upon dedesignation at June 30, 2007	$		$	407	$	
Reclassification adjustment of (gains) losses to earnings		696		(1,103)		
Income tax effect		(272)		272		
Net change, net of income taxes	$	424	$	(424)	$	

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

All of the Company s commodity derivative contracts are expected to settle by December 31, 2012. All the Company s commodity derivative contracts previously accounted for as cash flow hedges and dedesignated as hedges were settled on December 31, 2008.

Post 2008 commodity derivative contracts. After December 31, 2008 and through February 19, 2009, the Company entered into the following additional commodity derivative contracts:

	Aggregate Remaining Volume	Daily Volume	Index Price	Remaining Contract Period
Crude oil (volumes in Bbls):				
Price swap	600,000	1,644	$57.55(a)	1/1/10 - 12/31/10
Price collar	600,000	6,522	$45.00 - $49.00(a)	3/1/09 - 5/31/09

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

Note J. Debt

The Company s debt consists of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Senior Credit Facility	$ 630,000	$ 216,000
2nd Lien Credit Facility		109,900
Unamortized original issue discount on 2nd Lien Credit Facility		(496)
Total long-term debt	630,000	325,404
Current portion of 2nd Lien Credit Facility		2,000
Total debt	$ 630,000	$ 327,404

Senior credit facility. On July 31, 2008, the Company amended and restated its senior credit facility in various respects, including increasing the borrowing base to $960 million, subject to scheduled semiannual redeterminations, and extending the maturity date to July 31, 2013 (the Senior Credit Facility). The Company paid an arrangement fee of $14.4 million upon closing the Senior Credit Facility. At December 31, 2008, the Company had letters of credit outstanding under the Senior Credit Facility of approximately $275,000 and its availability to borrow additional funds was $329.7 million. In October 2008, the Company s $960 million borrowing base was reaffirmed until the next scheduled borrowing base redetermination in April 2009. Between scheduled borrowing base redeterminations the Company and, if requested by 662/3 percent of the lenders, the lenders may each request one special redetermination.

Advances on the Senior Credit Facility bear interest, at the Company s option, based on (i) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (3.25 percent at December 31, 2008) or (ii) 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 125 to 275 basis points and zero to 125 basis points, respectively, per annum depending on the balance outstanding. The Company pays commitment fees on the unused portion of the available borrowing base ranging from 25 to 50 basis points per annum.

The Senior Credit Facility also includes a same-day advance facility under which the Company may borrow funds on a daily basis from the administrative agent. Same day advances 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.

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CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s obligations under the Senior Credit Facility are secured by a first lien on substantially all of the Company s oil and gas properties. In addition, all of the Company s subsidiaries are guarantors and all general partner, limited partner and membership interests in the Company s subsidiaries owned by the Company have been pledged to secure borrowings under the Senior Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (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 to be no greater than 4.0 to 1.0, 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 and including the unfunded amounts under the Senior Credit Facility, 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 mergers and sales or transfer of assets; and (d) a restriction on the payment of cash dividends. At December 31, 2008, the Company was in compliance with its debt covenants.

2nd lien credit facility. On March 27, 2007, the Company entered into a second lien credit facility (the 2nd Lien Credit Facility), for a term loan facility in the amount of $200 million. The 2nd Lien Credit Facility was fully paid on July 31, 2008 from proceeds from the Company s Senior Credit Facility and the facility was terminated.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2008 are as follows:

	(In thousands)
2009	$
2010	
2011	
2012	
2013	630,000
Total	$ 630,000

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Cash payments for interest	$ 27,747	$ 41,036	$ 23,882
Amortization of original issue discount	58	98	
Amortization of deferred loan origination costs	2,157	1,338	1,494
Write-off of deferred loan origination costs and original issue discount	1,547	2,631	

Net changes in accruals	(1,237)	(6,414)	7,320
Interest costs incurred	30,272	38,689	32,696
Less: capitalized interest	(1,233)	(2,647)	(2,129)
Total interest expense	$ 29,039	$ 36,042	$ 30,567

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note K. Commitments and contingencies

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company s officers covered under such agreements total approximately $2.4 million.

Indemnifications. The Company has agreed to indemnify its directors and officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such proceedings and claims will not have a material adverse effect on the Company s consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company will continue to evaluate litigation against the Company on a quarter-by-quarter basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Acquisition commitments. In connection with the Acquisition, the Company agreed to pay certain employees of the Henry Entities bonuses of approximately $11.0 million in the aggregate at each of the first and second anniversaries of the closing of the Acquisition, respectively. Except as described below, these employees must remain employed with the Company to receive the bonus. A Henry Entities employee who is otherwise entitled to a full bonus will receive the full bonus (i) if the Company terminates the employee without cause, (ii) upon death or disability of such employee or (iii) upon a change in control of the Company. If such employee resigns or is terminated for cause the employee will not receive the bonus and the Company will be required to pay the sellers in the Acquisition 65 percent of the bonus amount not paid to the employee. The Company will reflect the bonus amounts to be paid to these employees as a period cost which will be included in the Company s results of operations over the period earned. Amounts that ultimately are determined to be paid to the sellers will be treated as a contingent purchase price and reflected as an adjustment to the purchase price. During 2008, the Company recognized $4.3 million of the obligation in its results of operations and $0.7 million as contingent purchase price.

Daywork commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company s future drilling commitments at December 31, 2008:

	Payments Due By Period (In thousands)				
	Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
Daywork drilling contracts	$ 5,584	$ 5,584	$	$	$

Daywork drilling contracts with related parties(a)	12,296	12,296			
Daywork drilling contracts assumed in the Henry Properties acquisition(b)	10,850	7,978	2,872		
Total contractual drilling commitments	$ 28,730	$ 25,858	$ 2,872	$	$

(a) Consists of daywork drilling contracts with Silver Oak Drilling, LLC, an affiliate of the Chase Group.

(b) A major oil and gas company which owns an interest in the wells being drilled and the Company are parties to these contracts. Only the Company s 25% share of the contract obligation has been reflected above.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2008, 2007 and 2006 were approximately $720,000, $288,000 and $685,000, respectively.

Future minimum lease commitments under non-cancellable operating leases at December 31, 2008 are as follows:

	(In thousands)
2009	$ 970
2010	985
2011	989
2012	981
2013	818
Total	$ 4,743

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 s provision for income taxes differed from the U.S. statutory rate of 35 percent primarily due to state income taxes and non-deductible expenses. The effective income tax rate for the years ended December 31, 2008, 2007 and 2006 was 36.8 percent, 38.7 percent and 42.2 percent, 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. At December 31, 2008 and 2007, the Company had no valuation allowances related to its deferred tax assets.

The Company adopted the provisions of FASB Interpretation No. 48 *Accounting for Uncertainty in Income Taxes* (FIN No. 48) an interpretation of FASB Statement No. 109 *Accounting for Income Taxes*, on January 1, 2007. At the time of adoption and at December 31, 2008, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 through 2008 remain subject to examination by major tax jurisdictions.

The FASB issued FIN No. 48-1, *Definition of Settlement in FASB Interpretation No. 48*, (FIN No. 48-1) to clarify when a tax position is effectively settled. FIN No. 48-1 provides guidance 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. FIN No. 48-1 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 s adoption of this pronouncement did not have a significant effect on its consolidated financial statements.

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 became effective for activities occurring on or after January 1, 2007.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The portion of tax expense attributable to the enactment of the Texas margin tax was $226,000 and $113,000 for the years ended December 31, 2008 and 2007, respectively.

Income tax provision. The Company s income tax provision and amounts separately allocated were attributable to the following items for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Income from operations	$ 162,085	$ 16,019	$ 14,379
Changes in stockholders equity:			
Net deferred hedge gains (losses)	(3,121)	(13,204)	4,200
Net settlement losses included in earnings	12,228	3,830	2,030
Tax benefits related to stock-based compensation	(3,614)		
	$ 167,578	$ 6,645	$ 20,609

The Company s income tax provision attributable to income from operations consisted of the following for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
	(In thousands)		
Current:			
U.S. federal	$ 8,080	$ 1,902	$ 1,527
U.S. state and local	521	401	234
	8,601	2,303	1,761
Deferred:			
U.S. federal	141,668	10,069	10,777
U.S. state and local	11,816	3,647	1,841
	153,484	13,716	12,618
	$ 162,085	$ 16,019	$ 14,379

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

	Years Ended December 31, 2008	2007	2006
	(In thousands)		
Income at U.S. federal statutory rate	$ 154,276	$ 14,483	$ 11,916
State income taxes (net of federal tax effect)	13,372	2,631	2,083
Stock-based compensation			380
Statutory depletion carryover		(613)	
Change in tax rate	(5,671)		
Nondeductible expense & other	108	(482)	
Expense for income taxes	$ 162,085	$ 16,019	$ 14,379

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008	December 31, 2007
	(In thousands)	
Deferred tax asset:		
Stock-based compensation	$ 5,569	$ 4,440
Derivative instruments		17,612
Statutory depletion carryover	1,635	613
Federal tax credit carryovers	8,525	1,195
Other	10,625	564
Total deferred tax assets	26,354	24,424
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	(557,011)	(269,938)
Intangible asset operating rights	(14,387)	
Derivative instruments	(65,689)	
Other	(235)	(54)
Total deferred tax liabilities	(637,322)	(269,992)
Net deferred tax liability	$ (610,968)	$ (245,568)

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.

The following purchasers individually accounted for ten percent or more of the consolidated oil and natural gas revenues, including the results of commodity hedges, during the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31, 2008	2007	2006
Navajo Refining Company, L.P.	59%	60%	52%
DCP Midstream LP	18%	23%	17%

At December 31, 2008, the Company had receivables from Navajo Refining Company, L.P. and DCP Midstream LP of $16.2 million and $3.7 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, 2008 and 2007, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note N. Related parties

Contract Operator Agreement and Transition Services Agreement. 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 its contract operator to provide certain services with respect to the Chase Group Properties. The initial term of the Contract Operator Agreement was five 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 continued to provide certain field level operating services on the Chase Group Properties. The Transition Services Agreement was terminated automatically on August 7, 2007 upon the Company s completion of the Company s initial public offering. Upon termination of such agreement, the Company s employees along with third party contractors assumed the operation of the subject properties.

The Company incurred charges from MEC of approximately $1.9 million and $18.2 million for the year ended December 31, 2008 and from the termination dates of the respective agreements through December 31, 2007, respectively, in the ordinary course of business. The Company incurred charges from MEC of approximately $18.2 million and $10.3 million during 2007 for services rendered under the Contract Operator Agreement and Transition Services Agreement through the termination dates of the respective agreements and the year ended December 31, 2006, respectively.

The Company had outstanding invoices payable to MEC of approximately zero and $0.4 million at December 31, 2008 and 2007, 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 $23.2 million, $43.8 million and $32.4 million for the years ended December 31, 2008, 2007 and 2006, respectively, for services rendered.

At December 31, 2008 and 2007, the Company had outstanding invoices payable to the other related party vendors identified above of approximately $21,000 and $1.7 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 $3.1 million, $2.4 million and $1.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. The Company owed royalty payments of approximately $146,000 and $315,000 to these members of the Chase Group at December 31, 2008 and 2007, respectively.

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 percent partnership interest. The Company paid approximately $332,000, $205,000 and $72,000 for the years ended December 31, 2008, 2007 and 2006, respectively.

The Company owed this partnership royalty payments of approximately $13,000 and $29,000 at December 31, 2008 and 2007, 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 percent 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, 2008, no payments were made related to this overriding royalty interest.

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The Company paid Caza approximately zero, $3,000 and $2.1 million for the years ended December 31, 2008, 2007 and 2006 for these interests. At December 31, 2008 and 2007, the Company had no outstanding invoices owed to Caza.

Working interests owned by employees. As part of the Henry Properties acquisition, the Company purchased oil and gas properties in which employees owned a working interest. The Company distributed revenues to these employees of approximately $155,000 and received joint interest payments from these employees of $635,000 for the year ended December 31, 2008. At December 31, 2008, the Company was owed by these employees approximately $300,000, which is reflected in accounts receivable related parties.

Note O. Net income per share

Basic net income per share is computed by dividing net income applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period. As discussed in Note F, agreements to sell stock to the Company s 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. All Bundled Capital Options were exercised prior to September 30, 2007. All Capital Options were exercised prior to March 31, 2008.

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 and restricted stock (as issued under the Plan and described in Note G). 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, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	**2007**	**2006**
	(In thousands)		

Weighted average common shares outstanding:			
Basic	79,206	64,316	47,287
Dilutive Bundled Capital Options		847	2,516
Dilutive Capital Options	6	154	192
Dilutive common stock options	1,134	901	714
Dilutive restricted stock	241	91	20
Diluted	80,587	66,309	50,729

CONCHO RESOURCES INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Since the Company had net income 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 313,354 shares, 366,250 shares and 450,000 of common stock for the years ended December 31, 2008, 2007 and 2006, respectively, were outstanding but not included in the computations of diluted income per share from continuing operations. Also excluded from the computation of diluted income per share for the year ended December 31, 2008, were 56,086 shares of restricted stock because the effect would be anti-dilutive.

Note P. Other current liabilities

The following table provides the components of the Company s other current liabilities at December 31, 2008 and 2007:

	December 31, 2008	December 31, 2007
	(In thousands)	
Other current liabilities:		
Accrued production costs	$ 15,489	$ 4,135
Payroll related matters	11,290	3,821
Accrued interest	353	1,590
Asset retirement obligations	2,611	912
Other	8,314	4,008
Other current liabilities	$ 38,057	$ 14,466

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CONCHO RESOURCES INC.

UNAUDITED SUPPLEMENTARY INFORMATION
December 31, 2008, 2007 and 2006

Capitalized Costs

	December 31, 2008	December 31, 2007
	(In thousands)	
Oil and gas properties:		
Proved	$ 2,316,330	$ 1,303,665
Unproved	377,244	251,353
Less: accumulated depletion	(306,990)	(167,109)
Net capitalized costs for oil and gas properties	$ 2,386,584	$ 1,387,909

Costs Incurred for Oil and Gas Producing Activities(a)

	Years Ended December 31, 2008	2007	2006
	(In thousands)		
Property acquisition costs:			
Proved	$ 597,713	$	$ 830,537
Unproved	240,294	7,293	220,295
Exploration	160,174	116,004	49,297
Development	178,842	64,524	124,817
Total costs incurred for oil and gas properties	$ 1,177,023	$ 187,821	$ 1,224,946

(a) The costs incurred for oil and gas producing activities includes the following amounts of asset retirement obligations:

	Years Ended December 31, 2008	2007	2006
	(In thousands)		
Proved property acquisition costs	$ 7,062	$	$ 6,155
Exploration costs	563	(15)	43
Development costs	(1,123)	315	1,095

Total	$ 6,502	$ 300	$ 7,293

Reserve Quantity Information

The estimates of proved oil and gas reserves, which are all located in the United States primarily in the Permian Basin region of Southeastern New Mexico and West Texas, 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 United States Securities and Exchange Commission (SEC) and the FASB, 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.

CONCHO RESOURCES INC.

UNAUDITED SUPPLEMENTARY INFORMATION (Continued)

The following table summarizes the prices utilized in the reserve estimates for 2008, 2007 and 2006. Commodity prices utilized for the reserve estimates were adjusted for location, grade and quality are as follows:

	December 31, 2008	2007	2006
Prices utilitzed in the reserve estimates before adjustments:			
Year-end West Texas Intermediate posted oil price per Bbl	$ 41.00	$ 92.50	$ 57.75
Year-end Henry Hub spot market natural gas price per MMBtu	$ 5.71	$ 6.80	$ 5.64

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.

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2008, 2007 and 2006, as well as proved developed reserves at the beginning and end of each respective year. Oil and condensate volumes are expressed in MBbls and natural gas volumes are expressed in MMcf.

	2008			2007			2006		
	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Total Proved Reserves:									
Balance, January 1	53,361	225,837	91,000	44,322	200,818	77,792	9,658	49,530	17,913
Purchase of minerals-in-place	20,837	56,022	30,174	105	354	164	27,163	137,963	50,157
Sales of minerals-in-place				(1)		(1)			
Discoveries and extensions(a)	24,194	73,380	36,424	13,140	48,751	21,265	10,226	39,427	16,797
Revisions of previous estimates	(7,521)	(34,323)	(13,242)	(1,191)	(12,022)	(3,195)	(430)	(16,595)	(3,196)
Production	(4,586)	(14,968)	(7,081)	(3,014)	(12,064)	(5,025)	(2,295)	(9,507)	(3,880)

Balance, December 31	86,285	305,948	137,275	53,361	225,837	91,000	44,322	200,818	77,791
Proved Developed Reserves:									
January 1	27,617	128,872	49,096	23,443	112,423	42,180	6,502	34,160	12,195
December 31	46,661	179,124	76,515	27,617	128,872	49,096	23,443	112,423	42,180

(a) The 2008, 2007 and 2006 discoveries and extensions included 14,533, 9,601 and 5,211 net MBoe, respectively, related to additions from the Company s infill drilling activities.

Standardized Measure of Discounted Future Net Cash Flows

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,

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CONCHO RESOURCES INC.

UNAUDITED SUPPLEMENTARY INFORMATION (Continued)

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.

The following table provides the standardized measure of discounted future cash flows at December 31, 2008, 2007 and 2006:

	December 31, 2008	December 31, 2007	December 31, 2006
	(In thousands)		
Oil and gas producing activities:			
Future cash inflows	$ 5,785,109	$ 6,507,955	$ 3,560,326
Future production costs	(1,666,380)	(1,517,415)	(995,335)
Future development and abandonment costs(a)	(668,005)	(484,140)	(484,462)
Future income tax expense	(919,251)	(1,482,633)	(530,212)
	2,531,473	3,023,767	1,550,317
10% annual discount factor	(1,332,488)	(1,591,993)	(839,968)
Standardized measure of discounted future cash flows	$ 1,198,985	$ 1,431,774	$ 710,349

(a) Includes $28.8 million, $19.5 million and $25.3 million of undiscounted asset retirement cash inflow estimated at December 31, 2008, 2007 and 2006, respectively, using current estimates of future salvage values less future abandonment costs. See Note E for corresponding information regarding the Company s discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future cash flows for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31, 2008	Years Ended December 31, 2007	Years Ended December 31, 2006
	(In thousands)		
Oil and gas producing activities:			
Purchases of minerals-in-place	$ 1,014,689	$ 4,054	$ 795,072
Sales of minerals-in-place	(24)	(54)	
Extensions and discoveries	426,208	511,519	156,266

Net changes in prices and production costs	(1,622,800)	802,584	(109,264)
Oil and gas sales, net of production costs	(473,841)	(249,866)	(166,236)
Changes in future development costs	74,160	72,441	(6,085)
Revisions of previous quantity estimates	(283,557)	(82,299)	(51,147)
Accretion of discount	255,660	85,533	23,085
Changes in production rates, timing and other	104,137	35,834	(10,119)
Change in present value of future net revenues	(505,368)	1,179,746	631,572
Net change in present value of future income taxes	272,579	(458,321)	(144,985)
	(232,789)	721,425	486,587
Balance, beginning of year	1,431,774	710,349	223,762
Balance, end of year	$ 1,198,985	$ 1,431,774	$ 710,349

CONCHO RESOURCES INC.

UNAUDITED SUPPLEMENTARY INFORMATION (Continued)

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2008 and 2007:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
Year ended December 31, 2008:				
Total operating revenues	$ 106,711	$ 137,383	$ 170,457	$ 119,238
Operating costs and expenses (excluding gains (losses) on derivatives not designated as hedges)	(48,205)	(54,942)	(90,889)	(121,229)
Gains (losses) on derivatives not designated as hedges	(17,178)	(102,456)	163,312	206,192
Income (loss) from operations	41,328	(20,015)	242,880	204,201
Net income (loss)	$ 22,365	$ (14,420)	$ 141,928	$ 128,829
Net income (loss) available to common stockholders	$ 22,365	$ (14,420)	$ 141,928	$ 128,829
Net income (loss) per common share Basic	$ 0.30	$ (0.19)	$ 1.75	$ 1.53
Net income (loss) per common share Diluted	$ 0.29	$ (0.19)	$ 1.72	$ 1.51
Year ended December 31, 2007:				
Total operating revenues	$ 60,346	$ 66,103	$ 69,098	$ 98,786
Operating costs and expenses (excluding gains (losses) on derivatives not designated as hedges)	(41,938)	(46,324)	(49,690)	(60,170)
Gains (losses) on derivatives not designated as hedges			3,088	(23,362)
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

Index of Exhibits

Exhibit Number	Exhibit
2.1	Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc., James C. Henry and Paula Henry, Henry Securities Ltd., Henchild LLC, Henry Family Investment Group, Henry Holding LP, Henry Energy LP, Aguasal Holding, HELP Investment LLC, Henry Capital LLC, Henry Operating LLC, Henry Petroleum LP, Quail Ranch LLC, Aguasal Management LLC, and Aguasal LP (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on August 6, 2007, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Concho Resources Inc., as amended March 25, 2008 (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on March 26, 2008, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Current Report on Form S-1/A on July 5, 2007, and incorporated herein by reference).
10.1	Credit Agreement, dated as of February 24, 2006, by and 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(filed as Exhibit 10.1 to the Company s Current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.2	Second Lien Credit Agreement, dated as of 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 (filed as Exhibit 10.2 to the Company s Current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.3	Form of Drilling Agreement with Silver Oak Drilling, LLC (filed as Exhibit 10.4 to the Company s Current Report on Form S-1/A on July 5, 2007, and incorporated herein by reference).
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 (filed as Exhibit 10.5 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.5	Transition Services Agreement dated April 23, 2007, between COG Operating LLC and Mack Energy Corporation (filed as Exhibit 10.3 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
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 (filed as Exhibit 2.1 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference). The Combination Agreement filed as Exhibit 2.1 omits certain of the schedules and exhibits to the Combination Agreement in accordance with Item 601 (b)(2) of Regulation S-K. A list briefly identifying the contents of all omitted schedules and exhibits is included with the Combination Agreement filed as Exhibit 2.1. Concho Resources agrees to furnish supplementally a copy of any omitted schedule or exhibit to the Securities and Exchange Commission upon request.
10.7	Software License Agreement dated March 2, 2006, between Enertia Software Systems and Concho Resources Inc. (filed as Exhibit 10.6 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.8	

	Leasehold Acquisition Agreement dated April 1, 2005, by and between Trey Resources, Inc. and COG Oil and Gas LP (filed as Exhibit 10.7 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.9	Transfer of Operating Rights (Sublease) in a Lease for Oil and Gas for Valhalla properties (filed as Exhibit 10.8 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.10	Assignment of Oil and Gas Leases from Caza Energy LLC (filed as Exhibit 10.9 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
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 (filed as Exhibit 10.10 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).

Exhibit Number	Exhibit
10.12	Business Opportunities Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.11 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.13	Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.12 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.14**	Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.13 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.15**	Concho Resources Inc. Summary of Executive Officer Compensation Program (filed as Exhibit 10.15 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.16**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.17**	Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company s Current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.18**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.19**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.20**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.2 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.21**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.22**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.4 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.23**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and David W. Copeland (filed as Exhibit 10.5 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.24**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.6 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.25**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.7 to the Company s current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).
10.26**	Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.23 to the Company s current Report on Form S-1 on April 24, 2007, and incorporated herein by reference).
10.27**	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).
10.28**	

	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).
10.29**	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).

Exhibit Number	Exhibit
10.30	Gas Purchase Contract between COG Oil & Gas LP and Duke Energy Field Services, LP dated November 1, 2006 (filed as Exhibit 10.25 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference). Confidential treatment of certain provisions of this exhibit has previously been granted by the Securities and Exchange Commission. Omitted material for which confidential treatment has been granted has been filed separately with the Securities and Exchange Commission.
10.31	Letter Agreement between COG Operating LLC and Navajo Refining Company, L.P. dated January 15, 2007 (filed as Exhibit 10.26 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.32	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 (filed as Exhibit 10.27 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.33	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 (filed as Exhibit 10.28 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.34**	Third Amendment to Credit Agreement, dated as of May 19, 2008, by and among Concho Resources Inc., certain of its subsidiaries, JPMorgan Chase Bank, N.A. and the other leaders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on May 23, 2008, and incorporated herein by reference).
10.35**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Leach and Beal (filed as Exhibit 10.29 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.36**	Form of option letter agreement among Concho Resources Inc., Concho Equity Holdings Corp. and each of Messrs. Copeland, Kamradt, Thomas and Wright (filed as Exhibit 10.30 to the Company s current Report on Form S-1 on June 6, 2007, and incorporated herein by reference).
10.37**	Form of Amendment to Stock Option Award Agreement with executive officers related to the Pre-Combination Options (filed as Exhibit 10.1 to the Company s current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.38**	Form of Amendment to Nonstatutory Stock Option Agreement with executive officers related to the June 2006 Options (filed as Exhibit 10.2 to the Company s current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.39**	Form of Restricted Stock Agreement with executive officers related to the June 2006 Options (filed as Exhibit 10.3 to the Company s current Report on Form 8-K on November 20, 2007, and incorporated herein by reference).
10.40	Summary of Director Compensation Program (filed as Exhibit 10.41 to the Company s Current Report on Form 10-K on March 28, 2008, and incorporated herein by reference).
10.41	Common Stock Purchase Agreement, dated June 5, 2008, by and among Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 9, 2008, and incorporated herein by reference).
10.42	Registration Rights Agreement, dated July 31, 2008, by and between Concho Resources Inc. and the purchasers named therein (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
10.43	

	Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., Calyon New York Branch, ING Capital LLC and BNP Paribas and certain other lenders party thereto (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).
21.1(a)	Subsidiaries of Concho Resources Inc.
23.1(a)	Consent of Grant Thornton LLP
23.2(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3(a)	Consent of Cawley, Gillespie & Associates, Inc.
31.1(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Exhibit
31.2(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or arrangement.