CONCHO RESOURCES INC
Form S-1/A
June 06, 2007

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As filed with the Securities and Exchange Commission on June 6, 2007

Registration No. 333-142315

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Amendment No. 1
to
Form S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Concho Resources Inc.
(Exact name of registrant as specified in charter)

Delaware	**1311**	**76-0818600**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

550 West Texas Avenue, Suite 1300
Midland, Texas 79701
(432) 683-7443
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

David W. Copeland
Vice President and General Counsel
550 West Texas Avenue, Suite 1300
Midland, Texas 79701
(432) 683-7443
(Name, address, including zip code, and telephone number, including area code,

of agent for service)

With a copy to:

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New York, New York 10005
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Approximate date of commencement of proposed sale to the public: As soon as practicable on or after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to completion, dated June 6, 2007

Preliminary prospectus

shares

Concho Resources Inc.

Common Stock

Concho Resources Inc. is selling shares of common stock, and the selling stockholders identified in this prospectus are selling an additional shares. We will not receive any of the proceeds from the sale of the shares by the selling stockholders. This is the initial public offering of our common stock. The estimated initial public offering price is between $ and $ per share.

Prior to this offering, there has been no public market for our common stock. We have been authorized to apply to have our common stock listed on the New York Stock Exchange under the symbol CXO.

	Per share	Total
Initial public offering price	$	$
Underwriting discount	$	$
Proceeds to Concho Resources Inc., before expenses	$	$
Proceeds to selling stockholders, before expenses	$	$

Certain selling stockholders have granted the underwriters an option for a period of 30 days to purchase up to an aggregate of additional shares of our common stock on the same terms and conditions set forth above to cover over-allotments, if any.

Investing in our common stock involves a high degree of risk. See Risk factors beginning on page 16.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to investors on , 2007.

JPMorgan **Banc of America Securities LLC**

Lehman Brothers

BNP PARIBAS

Merrill Lynch & Co.

UBS Investment Bank

Wachovia Securities

, 2007

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You should rely only on the information contained in this prospectus and the registration statement of which this prospectus is a part. We have not authorized anyone to provide you with information different from that contained in this prospectus. We and the selling stockholders are offering to sell, and seeking offers to buy, shares of our common stock only in jurisdictions where offers and sales are permitted. The information contained in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of our common stock.

No action is being taken in any jurisdiction outside the United States to permit a public offering of our common stock or possession or distribution of this prospectus in that jurisdiction. Persons who come into possession of this prospectus in jurisdictions outside the United States are required to inform themselves about and to observe any restrictions as to this offering and the distribution of this prospectus applicable to those jurisdictions.

Concho and Concho Resources are registered trademarks of ours. Other products, services and company names mentioned in this prospectus are the service marks/trademarks of their respective owners.

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Industry and market data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications, reports by market research firms or other published independent sources. Some data are also based on our good faith estimates. Although we believe these third-party sources are reliable, we have not independently verified the information.

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Prospectus summary

This summary highlights information contained elsewhere in this prospectus. Because this section is only a summary, it does not contain all of the information that may be important to you or that you should consider before making an investment decision. For a more complete understanding of this offering, we encourage you to read this entire prospectus, including the information contained under the heading Risk factors. You should read the following summary together with the more detailed information, pro forma financial information and consolidated financial information and the notes thereto included elsewhere in this prospectus. In this prospectus, unless the context otherwise requires, the terms we, us, our and Concho Resources refer to Concho Resources Inc. and its subsidiarie

In this prospectus, pro forma means after giving pro forma effect to the combination transaction that occurred on February 27, 2006 as if the combination transaction occurred on January 1, 2006 with respect to pro forma financial and operating information for the three months ended March 31, 2006 and the year ended December 31, 2006, unless otherwise noted. Please read Business and properties Combination transaction for more information about the combination transaction.

We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of terms beginning on page A-1 of this prospectus. Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their option to purchase additional shares from certain selling stockholders.

Our business

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

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

Our operations are primarily concentrated in the Permian Basin, the largest onshore oil and gas basin in the United States. As of December 31, 2006, 99% of our total estimated net proved reserves were located in the Permian Basin and consisted of approximately 57% crude oil and 43% natural gas. This basin is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. The primary producing formation in the Permian Basin under our core properties in Southeast New Mexico is the Paddock interval of the Yeso formation, which is located at depths ranging from 3,800 feet to 5,800 feet. We have also discovered reserves and are producing oil and natural gas from the Blinebry interval of the Yeso formation, the top of

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which is located approximately 400 feet below the base of the Paddock interval. In addition, we have assembled a multi-year inventory of development drilling and exploitation projects, including further projects to evaluate the aerial extent of the Blinebry interval, that we believe will allow us to grow proved reserves and production. We have also acquired significant acreage positions in unconventional emerging resource plays, where we intend to apply horizontal drilling, advanced fracture stimulation and/or enhanced recovery technologies.

Following the formation of our company, we drilled 140 gross (86.4 net) wells in 2006, 89% of which were completed as producers, 7% of which were dry holes and 4% of which are awaiting completion. In addition, following the formation of our company, we recompleted 103 gross (77.1 net) wells in 2006, 98% of which were productive. As a result, we have increased our total estimated net proved reserves by approximately 51 Bcfe from 416 Bcfe as of December 31, 2005, on a pro forma basis, to 467 Bcfe as of December 31, 2006, while producing approximately 26 Bcfe of oil and natural gas on a pro forma basis during the year ended December 31, 2006. In addition, following the formation of our company, we increased our average net daily production from 62 MMcfe during March 2006 to 80 MMcfe during March 2007.

The following table provides a summary of selected operating information of our conventional properties in the Permian Basin, which is our core operating area, and in our unconventional emerging resource plays. 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. We set forth our definition of PV-10 (a non-GAAP financial measure) and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows under Non-GAAP financial measures and reconciliations.

	As of December 31, 2006					As of March 31, 2007		Three months ended March 31, 2007
Areas	**Total proved reserves (Bcfe)**	**PV-10 ($ in millions)**	**Pro forma reserve/ production index[1] (years)**	**Identified drilling locations[2]**	**Identified recompletion projects[2]**	**Total gross acreage**	**Total net acreage**	**Average net daily production (MMcfe/d)**
Permian Basin								
Southeast New Mexico	387.5	$ 782.6	18.7	1,505	489	170,275	76,583	63.8
West Texas	70.2	154.5	15.5	148	49	91,687	34,765	13.4
Emerging Plays and Other[3]	9.1	16.9	19.2	23	2	234,098	125,245	2.8
Total	466.8	$ 954.0	18.1	1,676	540	496,060	236,593	80.0

(1)

The Pro forma reserve/production index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing pro forma production during the year ended December 31, 2006, into the proved reserve quantity as of December 31, 2006. Pro forma production during the year ended December 31, 2006 was 25,735.0 MMcfe, consisting of 20,734.0 MMcfe in the Southeast New Mexico part of the Permian Basin, 4,526.5 MMcfe in the West Texas part of the Permian Basin and 474.5 MMcfe in Emerging Plays and Other. Pro forma production information assumes the combination transaction had taken place on January 1, 2006.

(2) The identified drilling locations and identified recompletion projects listed in the table above included 817 drilling locations and recompletion projects for which proved reserves had been included in our reserve reports as of December 31, 2006.

(3) Information with respect to Other includes conventional oil and gas operations on properties that are not located in the Permian Basin. As of December 31, 2006, 3.1 Bcfe of the proved reserves and $5.4 million of the PV-10 as well as one of the identified drilling locations and two identified recompletion projects were related to oil and natural gas properties categorized as Other and not as Emerging Plays. In addition, as of March 31, 2007, 4,948 gross (797 net) acres reflected above were categorized as Other, and 1.1 MMcfe/d of the average daily production during the three months ended March 31, 2007 reflected above were categorized as Other.

An unconventional emerging resource play generally consists of a large area that, based on its geological and geophysical characteristics, indicates the possible existence of a continuous accumulation of hydrocarbons. These plays are typically associated with tight, fractured rocks, such as fractured shales, fractured carbonates, coal seams and tight sands, which may serve as the source of the hydrocarbons and as the productive reservoir. In our unconventional emerging resource plays, we target areas where we can acquire large undeveloped acreage positions and apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies to achieve economic, repeatable production results. As of March 31, 2007, we held interests in 229,150 gross (124,448 net) acres in six unconventional emerging resource plays. Our current positions include acreage in:

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

the Central Basin Platform of West Texas, where we plan to target the Woodford Shale;

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

the Val Verde Basin of West Texas, where we plan to drill our first test well in 2007, which will target the Ellenburger Dolomite and the Canyon Sands;

the North Dakota portion of the Williston Basin, where we have drilled two exploratory wells targeting the Bakken Shale; and

the eastern Arkoma Basin in Arkansas, where we plan to drill our first test well prior to March 31, 2008, which will target the Fayetteville Shale.

Our exploration and development budget for our oil and gas properties for the year ending December 31, 2007 is approximately $154 million. We plan to spend approximately 87% of our capital budget on exploration and development activities associated with our conventional properties in the Permian Basin, 3% for leasehold acquisitions and 10% for exploration activities in our unconventional emerging resource plays. If we achieve successful results from exploratory drilling in our unconventional emerging resource plays, we may allocate a greater portion of our planned 2007 capital expenditure budget to those plays.

Our business strategy

Our goal is to enhance stockholder value through profitably increasing reserves, production and cash flow by executing our strategy as described below:

Exploit our multi-year project inventory. We believe our multi-year drilling and exploitation inventory of 2,216 drilling locations and recompletion projects on our existing properties as of December 31, 2006 will allow us to grow our proved reserves and production for the next several years.

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Enhance production from our existing properties through development of additional producing horizons and enhanced recovery methods. We have begun to evaluate additional productive horizons underlying certain of our existing producing horizons in Southeast New Mexico. During 2006, we drilled 52 wells in the Blinebry interval, all of which have since been completed as producers. In addition, we are evaluating the feasibility of enhanced recovery operations on a significant portion of our Southeast New Mexico properties.

Pursue the acquisition, exploration and development of unconventional emerging oil and natural gas resource plays. We have assembled an exploration team to target unconventional emerging resource plays. Members of our technical staff, consisting of six petroleum engineers, seven geoscientists and eight landmen, have, on average, more than 23 years experience in the industry.

Make opportunistic acquisitions that meet our strategic and financial objectives. We seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation, as well as other properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations.

Our strengths

We have a number of strengths that we believe will help us successfully execute our strategy:

Experienced and incentivized management team. Our executive officers average over 19 years of experience in the oil and gas industry, having led both public and private oil and natural gas exploration and production companies, all of which have had substantially all of their operations in our core area of the Permian Basin.

History of growth and capital efficiency. Despite increasing costs of oilfield services and equipment in our areas of operation, we added 101 Bcfe of proved reserves in 2006 through new discoveries and extensions, excluding revisions of previous estimates, at a total cost of $193.3 million.

Large inventory of drilling and recompletion opportunities. As of December 31, 2006, we had identified multiple undrilled well locations and recompletion opportunities, with proved reserves attributed to a portion of such locations and opportunities. We plan to drill 142 wells and recomplete 95 wells during 2007.

Geographically concentrated operations. The geographic concentration of our current operations in the Permian Basin allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, in addition to further leveraging our base of technical expertise in this region.

Significant operational control. Our high proportion of operated properties enables us to exercise a significant level of control over the amount and timing of expenses, capital allocation and other aspects of exploration and development.

Combination transaction

We were formed as a Delaware corporation on February 22, 2006, in connection with a combination transaction whereby certain of the stockholders of Concho Equity Holdings Corp. exchanged their equity interests in that company for approximately 52 million shares of our

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common stock and options to purchase shares of our common stock, and each of Chase Oil Corporation, Caza Energy LLC and their affiliated oil and gas working interest owners (which we refer to herein as the Chase Group) contributed their interests in certain oil and gas properties to our company in exchange for approximately 70 million shares of our common stock and total cash payments of approximately $409 million. Upon the initial closing of the combination transaction on February 27, 2006, the executive officers of Concho Equity Holdings Corp. became the executive officers of our company. For more information about the combination transaction, please see Business and properties Combination transaction. Prior to the completion of this offering, the field operations of the oil and gas properties we acquired from the Chase Group were conducted on our behalf and at our direction by employees of Mack Energy Corporation, an affiliate of Chase Oil. Upon the completion of this offering, our employees, along with third party contractors, if necessary, will assume those operations. For more information about our transactions with certain affiliates of Chase Oil, please see Certain relationships and related party transactions.

Concho Equity Holdings Corp. was formed in April 2004 by our existing senior management team and private equity investors, and it commenced oil and gas operations in December 2004 upon its acquisition of certain oil and natural gas properties located in Southeast New Mexico and West Texas from Lowe Partners, L.P. for approximately $117 million, which properties we refer to herein as the Lowe Properties.

Risk factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. You should read carefully the section entitled Risk factors for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our business strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

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

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

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

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

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

- The unavailability or high cost of drilling and workover rigs, equipment, supplies, materials, electricity, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget or on a timely basis.

- Substantially all of our producing properties are located in Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. Furthermore, approximately 53% of our proved reserves as of December 31, 2006, are from the Yeso formation, which includes both the Paddock and Blinebry intervals, within this geographic area, thus making us vulnerable to risks associated with this concentration of assets.

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

For a discussion of other considerations that could negatively affect us, including risks related to this offering and our common stock, see Risk factors and Cautionary statement regarding forward-looking statements.

Corporate information

Concho Resources Inc. is a Delaware corporation. Our principal executive offices are located at 550 West Texas Avenue, Suite 1300, Midland, Texas 79701, and our telephone number at that address is (432) 683-7443.

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The offering

Common stock offered by us:	shares
Common stock offered by the selling stockholders:	shares
Total common stock offered hereby:	shares
Common stock to be outstanding immediately following the offering:	shares
Use of proceeds:	We intend to use the net proceeds from the sale of our shares to repay a portion of our existing indebtedness. See Use of proceeds. We will not receive any of the proceeds from the sale of the shares by the selling stockholders. See Principal and selling stockholders.
Dividend policy:	We do not anticipate paying any cash dividends on our common stock.
Proposed New York Stock Exchange symbol:	CXO
Risk factors:	See Risk factors and the other information included in this prospectus for a discussion of the factors you should consider carefully before deciding to invest in shares of our common stock.

The number of shares of our common stock outstanding after this offering is based on shares of common stock outstanding as of , 2007, and excludes:

- shares of our common stock reserved for issuance upon exercise of stock options granted under our stock option plans, at a weighted average exercise price of $ per share; and
- shares of our common stock reserved for issuance pursuant to future awards under our 2006 Stock Incentive Plan.

Other information about this prospectus

Unless specifically stated otherwise, the information in this prospectus:

- reflects a reverse stock split of our shares of common stock effected immediately prior to the completion of this offering;
- assumes no exercise of the underwriters over-allotment option; and

assumes an initial public offering price of $, which is the mid-point of the range set forth on the front cover page of this prospectus.

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Summary historical and pro forma consolidated financial data

This section presents our summary historical and pro forma consolidated financial data. The summary historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following table shows summary historical financial data related to Concho Resources (as the accounting successor to Concho Equity Holdings Corp.), combined financial data of the properties we acquired from the Chase Group (which we refer to as the Chase Group Properties) and unaudited pro forma financial data of Concho Resources as of and for the year ended December 31, 2006. 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 Resources such that Concho Equity Holdings Corp. is now our wholly owned subsidiary.

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

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

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

On February 27, 2006, the initial closing of the combination transaction occurred. Pursuant to the combination transaction, Concho Resources acquired the Chase Group Properties for approximately 70 million shares of common stock and approximately $409 million in cash.

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

The summary historical financial data for the Chase Group Properties for the years ended December 31, 2004 and 2005 are derived from the audited financial statements of the Chase Group Properties. The summary historical financial data for Concho Resources for the period from inception (April 21, 2004) through December 31, 2004, and for the years ended December 31, 2005 and 2006, are derived from the audited financial statements of Concho Resources. The summary historical financial data for Concho Resources for the three months ended March 31, 2006 and 2007, are derived from the unaudited financial statements of Concho Resources.

The summary pro forma financial data for the year ended December 31, 2006 set forth in the following table are derived from the unaudited pro forma financial statements of Concho Resources included in this prospectus. The pro forma statement of operations data has been prepared as if the closing of the combination transaction had taken place as of January 1, 2006.

Our balance sheet data as of March 31, 2007, as adjusted, gives effect to the following transactions:

the issuance by us of shares of common stock in this offering;

- the repayment by our executive officers of certain loans made by our company to our executive officers prior to the filing of the registration statement of which this prospectus is a part; and

- the repayment of a portion of our outstanding indebtedness using net proceeds from this offering as described in Use of proceeds.

You should read the following data along with Selected historical and pro forma consolidated financial information, 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 prospectus. You should also read the pro forma information together with the unaudited pro forma combined financial statements and related notes included in this prospectus.

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The following table includes the non-GAAP financial measure EBITDA. For a definition of this measure and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with generally accepted accounting principles, which we refer to as GAAP, please read Non-GAAP financial measures and reconciliations.

	Chase Group Properties			Concho Resourc				
			Inception (April 21, 2004)			Pro forma year		
	Years ended December 31,		through December 31,	Years ended December 31,		ended December 31,	Three m ended Mar	
sands, except per share amounts)	2004	2005	2004	2005	2006	2006	2006	
						(unaudited)	(unaudited)	(unau
nt of operations data:								
ng revenues:								
	$ 66,529	$ 73,132	$ 1,851	$ 31,621	$ 131,773	$ 145,713	$ 16,404	$
gas sales	41,247	46,546	1,771	23,315	66,517	74,033	9,248	
erating revenues	107,776	119,678	3,622	54,936	198,290	219,746	25,652	
ng costs and expenses:								
gas production	11,762	12,979	512	10,923	22,060	24,456	3,929	
gas production taxes	9,202	10,298	234	3,712	15,762	17,602	1,981	
ion and abandonments	179		1,850	2,666	5,612	5,612	906	
tion, depletion and accretion	20,459	19,092	963	11,574	61,009	66,520	7,260	
ents of proved oil and gas properties	3,233	194		2,295	9,891	9,892	105	
drilling fees stacked rigs								
and administrative	1,387	1,702	3,086	8,055	12,577	12,861	2,437	
sed compensation			1,128	3,252	9,144	9,144	6,622	
ve portion of cash flow hedges				1,148	(1,193)	(1,193)	786	
ss on derivatives not designated as								
	7,936	1,062	(684)	5,001				
erating costs and expenses	54,158	45,327	7,089	48,626	134,862	144,894	24,026	
(loss) from operations	53,618	74,351	(3,467)	6,310	63,428	74,852	1,626	
come (expense):								

expense			(272)	(3,096)	(30,567)	(35,790)	(3,610)	(
et			168	779	1,186	1,186	303	
her expense			(104)	(2,317)	(29,381)	(34,604)	(3,307)	(
(loss) before income taxes	53,618	74,351	(3,571)	3,993	34,047	40,248	(1,681)	
ax (expense) benefit			915	(2,039)	(14,379)	(16,797)	253	
me (loss)	$ 53,618	$ 74,351	(2,656)	1,954	19,668	23,451	(1,428)	
d stock dividends			(804)	(4,766)	(1,244)		(1,146)	
induced conversion of preferred					11,601		11,601	
me (loss) applicable to n shareholders			$ (3,460)	$ (2,812)	$ 30,025	$ 23,451	$ 9,027	$
A[1] (unaudited)	$ 74,077	$ 93,443	$ (2,336)	$ 18,663	$ 125,623	$ 142,558	$ 9,189	$
rnings (loss) per share:								
me (loss) per share			$ (1.74)	$ (0.35)	$ 0.32	$ 0.22	$ 0.19	$
sed in basic earnings (loss) per share			1,987	8,117	94,575	108,335	47,951	1
earnings (loss) per share:								
me (loss) per share			$ (1.74)	$ (0.35)	$ 0.30	$ 0.20	$ 0.17	$
sed in diluted earnings (loss) per			1,987	8,117	101,458	115,412	53,005	1

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(In thousands)	Chase Group Properties Years ended December 31, 2004	2005	Concho Resources Inc. Inception (April 21, 2004) through December 31, 2004	Years ended December 31, 2005	2006	Three months ended March 31, 2006	2007
						(unaudited)	(unaudited)
Other financial data:							
Net cash provided by (used in) operations	$ 84,202	$ 93,162	$ (2,193)	$ 25,070	$ 112,181	$ 11,615	$ 31,049
Net cash provided by (used in) investing	(30,045)	(35,611)	(122,473)	(61,902)	(596,852)	(447,018)	(36,564)
Net cash provided by (used in) financing	(54,157)	(57,551)	125,322	45,358	476,611	426,221	6,966
Capital expenditures	25,451	32,352	116,880	72,758	1,226,180	1,039,414	27,430

(In thousands)	Chase Group Properties As of December 31, 2004	2005	Concho Resources Inc. 2004	As of December 31, 2005	2006	As of March 31, 2007	As adjusted as of March 31, 2007(2)
						(unaudited)	(unaudited)
Balance sheet data:							
Cash and cash equivalents	$	$	$ 656	$ 9,182	$ 1,122	$ 2,573	
Property and equipment, net	135,568	149,042	115,455	170,583	1,320,655	1,327,095	1,327,095
Total assets	145,100	161,792	130,717	232,385	1,390,072	1,380,339	
Long-term debt, including current maturities			53,000	72,000	495,500	505,000	
Stockholders equity/net investment	134,014	150,814	71,710	109,670	575,156	574,791	

(1) EBITDA is defined as income before accounting changes, plus (1) interest, the amortization of related debt issuance costs and other financial costs, net of capitalized interest, (2) federal and state income taxes and

(3) depreciation, depletion and accretion. See Non-GAAP financial measures and reconciliations.

(2) A $1.00 increase (decrease) in the assumed initial public offering price per share would decrease (increase) long-term debt, including current maturities by $ and would increase (decrease) stockholders equity by $, assuming the number of shares offered by us set forth on the cover page of this prospectus remains the same and after deducting underwriting discounts and estimated offering expenses payable by us.

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Summary reserve and pro forma production and operating data (unaudited)

The following estimates of net proved oil and natural gas reserves as of December 31, 2006 and pro forma net proved oil and natural gas reserves as of December 31, 2005, are based on reports prepared by Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc., independent petroleum engineers. In preparing their reports, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. evaluated properties representing 100% of our PV-10 as of the end of the applicable periods. Summaries of the Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. reports on our proved reserves as of December 31, 2006, are attached to this prospectus as Annex A and Annex B, respectively. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC. Please read Risk factors, Management s discussion and analysis of financial condition and results of operations, Business and properties Our oil and natural gas reserves, Business and properties Our production, prices and expenses, and the Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. summary reports included in this prospectus in evaluating the material presented below. The pro forma reserve data was prepared as if the combination transaction had taken place on December 31, 2005 for proved reserves data. The pro forma production data was prepared as if the combination transaction had taken place on January 1, 2006 for production, price and cost data.

	Pro forma as of December 31, 2005	As of December 31, 2006
Proved reserves:		
Oil (MBbl)	37,492	44,322
Natural gas (MMcf)	190,938	200,818
Natural gas equivalent (MMcfe)	415,890	466,750
Proved developed reserves percentage	55.0%	54.2%
PV-10 (in millions)(1)	$ 1,324.5	$ 954.0
Estimated reserve life (in years)(2)	18.9	18.1

(1) PV-10 is a non-GAAP financial measure and generally differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. See Non-GAAP financial measures and reconciliations. Prices used in the computation of future net cash flows were adjusted for location and quality by field, and were $61.04 per Bbl and $10.08 per MMBtu for purposes of estimating pro forma net proved reserves as of December 31, 2005 and were $57.75 per Bbl and $5.64 per MMBtu for purposes of estimating net proved reserves as of December 31, 2006.

(2) Calculated by dividing proved reserves by pro forma production volumes for the years indicated.

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	Pro forma year ended December 31, 2006	Three months ended March 31, 2007
Net production volumes:		
Oil (MBbl)	2,539.6	708.9
Natural gas (MMcf)	10,497.6	2,952.2
Natural gas equivalent (MMcfe)	25,735.0	7,205.5
Average prices:		
Oil, without hedges ($/Bbl)	$ 60.13	$ 54.09
Oil, with hedges ($/Bbl)	$ 57.38	$ 55.54
Natural gas, without hedges ($/Mcf)	$ 6.94	$ 7.06
Natural gas, with hedges ($/Mcf)	$ 7.05	$ 7.10
Natural gas equivalent, without hedges ($/Mcfe)	$ 8.76	$ 8.21
Natural gas equivalent, with hedges ($/Mcfe)	$ 8.54	$ 8.37
Operating costs and expenses:		
Oil and gas production ($/Mcfe)	$ 0.95	$ 1.01
Oil and gas production taxes ($/Mcfe)	$ 0.68	$ 0.65
General and administrative ($/Mcfe)	$ 0.50	$ 0.48
Depreciation and depletion expense ($/Mcfe)	$ 2.57	$ 2.70

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Non-GAAP financial measures and reconciliations
(unaudited)

PV-10

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

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 as of December 31, 2005 and 2006.

(Dollars in millions)	**Pro forma 2005**	**2006**
PV-10	$ 1,324.5	$ 954.0
Present value of future income tax discounted at 10%	(379.7)	(243.7)
Standardized measure of discounted future cash flows	$ 944.8	$ 710.3

EBITDA

We define EBITDA as income before accounting changes, plus (1) interest, the amortization of related debt issuance costs and other financing costs, net of capitalized interest, (2) federal and state income taxes and (3) depreciation, depletion and accretion. EBITDA is not a measure of net income or cash flow as determined by generally accepted accounting principles.

Our EBITDA measure provides additional information which may be used to better understand our operations. EBITDA is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income, as an indicator of our operating performance, as an alternative to cash flows from operating activities or as a measure of liquidity. Certain items excluded from EBITDA are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic cost of depreciable assets, none of which are components of EBITDA. EBITDA as used by us may not be comparable to similarly titled measures reported by other companies. We believe that EBITDA is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, EBITDA can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies, without regard to

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financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis. EBITDA on a pro forma basis for the year ended December 31, 2006, gives effect to the combination transaction as if it had closed on January 1, 2006.

The following table provides a reconciliation of net income (loss) to EBITDA.

	Chase Group Properties		Concho Resources Inc.					
	Years ended December 31,		Inception (April 21, 2004) through December 31,	Years ended December 31,		Pro forma year ended December 31,	Three months ended March 31,	
(In thousands)	**2004**	**2005**	**2004**	**2005**	**2006**	**2006**	**2006**	**2007**
Net income (loss)	$ 53,618	$ 74,351	$ (2,656)	$ 1,954	$ 19,668	$ 23,451	$ (1,428)	$ 4,623
Interest expense			272	3,096	30,567	35,790	3,610	10,675
Income tax expense (benefit)			(915)	2,039	14,379	16,797	(253)	3,375
Depreciation, depletion and accretion	20,459	19,092	963	11,574	61,009	66,520	7,260	19,537
EBITDA	$ 74,077	$ 93,443	$ (2,336)	$ 18,663	$ 125,623	$ 142,558	$ 9,189	$ 38,210

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Risk factors

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

Risks relating to our business

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

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

- the level of consumer demand for oil and natural gas;
- the domestic and foreign supply of oil and natural gas;
- commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the price and level of imports of foreign oil and natural gas;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East and South America;
- technological advances affecting energy consumption; and
- worldwide economic conditions.

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

Furthermore, recent oil prices have been high compared to historical prices and have been particularly volatile. For example, the NYMEX crude oil price per Bbl was $32.52, $43.45, $61.04 and $61.15 as of December 31, 2003, 2004, 2005 and 2006, respectively, and during 2006 the NYMEX crude oil spot price ranged from a high of $77.03 to a low of $55.81. In addition, natural gas prices have been subject to significant fluctuations during the past several years. For example, the NYMEX natural gas price per Mcf was $5.96, $6.18, $10.08 and $5.64 as of December 31, 2003, 2004, 2005 and 2006, respectively, and during 2006 the NYMEX natural gas spot price ranged from a high of $9.87 to a low of $3.63.

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

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

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

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

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

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

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. For example, in connection with the preparation of our total estimated net proved reserves as of December 31, 2006, we revised our estimated natural gas reserves downward by 16,595 MMcf from our previous estimates. This reduction in natural gas reserves was primarily because of the decrease in natural gas prices during 2006. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If oil prices decline by $1.00 per Bbl, then our PV-10 as of December 31, 2006, would decrease from $954.0 million to $934.9 million. If natural gas prices decline by $0.10 per Mcf, then our PV-10 as of December 31, 2006, would decrease from $954.0 million to $945.3 million. Any adjustments to the estimates of proved reserves or decreases in the price of oil or natural gas may decrease the value of our common stock.

Almost all of our producing properties are located in the Permian Basin region of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, a substantial portion of our proved reserves as of December 31, 2006, are from a single producing horizon within this area.

Our producing properties are geographically concentrated in the Permian Basin region of Southeast New Mexico and West Texas. At December 31, 2006, approximately 99% of our PV-10 was attributable to properties located in the Permian Basin. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from these wells caused by significant governmental regulation, processing or transportation capacity constraints, market limitations, curtailment of production or interruption of the processing or transportation of oil and natural gas produced from the wells in these areas.

In addition to the geographic concentration of our producing properties described above, approximately 53% of our proved reserves as of December 31, 2006, were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and gas properties located in Southeast New Mexico. This concentration of assets within one producing horizon exposes us to risks such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within the field. Furthermore, we are in the process of drilling and completing wells in the Blinebry interval (the lower member of the Yeso formation), which lies beneath the Paddock interval on certain of our properties located in Southeast New Mexico. These activities could result in delays in the production of our proved reserves from the Paddock interval in the event that commingling of both formations is imprudent or otherwise not feasible.

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

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

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

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

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

Our commodity price risk management activities could have the effect of reducing our revenues and the value of our common stock. As of March 31, 2007, the net unrealized loss on our commodity price risk management contracts was $10.1 million. An average increase in the commodity price of $1 per barrel of crude oil and $0.10 per Mcf for natural gas would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts as reflected on our balance sheet as of March 31, 2007 of approximately $2.1 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 continue to increase and our derivatives contracts remain in place. See Management s discussion and analysis of financial condition and results of operations Liquidity and capital resources Hedging.

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

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

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

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. For example, during the first three months of 2007, we curtailed our drilling program in order to preserve liquidity until we could complete our second lien term loan facility. As of March 31, 2007, our total debt outstanding was $505.0 million, and $69.0 million was available to be borrowed under our revolving credit facility. Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $154 million for exploration and development expenditures in 2007. See Management s discussion and analysis of financial condition and results of operations Liquidity and capital resources Future capital expenditures and commitments. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of your common stock. Additional borrowings under our revolving credit facility or the issuance of additional debt will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our bank credit facilities impose certain limitations on our ability to incur additional indebtedness other than indebtedness under our revolving credit facility. If we desire to issue additional debt securities other than as expressly permitted under our bank credit facilities, we will be required to seek the consent of the lenders in accordance with the requirements of those facilities, which consent may be withheld by the lenders under our bank credit facilities in their discretion. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

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

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

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

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

Our management has specifically identified and scheduled the drilling and recompletion of our drilling and recompletion opportunities as an estimation of our future multi-year development activities on our existing acreage. As of December 31, 2006, we had identified 1,676 drilling locations with proved undeveloped reserves attributable to 595 of such locations, and 540 recompletion opportunities with proved reserves attributed to 222 of such opportunities. These identified opportunities represent a significant part of our growth strategy. Our ability to drill and develop these opportunities depends on a number of uncertainties, including the availability of capital, equipment, services and personnel, seasonal conditions, regulatory and third party approvals, oil and natural gas prices, costs and drilling and recompletion results. Because of these uncertainties, we may never drill or recomplete the numerous potential opportunities we have identified or produce oil or natural gas from these or any other potential opportunities. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our business.

Approximately 46% of our total estimated net proved reserves as of December 31, 2006, were undeveloped, and those reserves may not ultimately be developed.

As of December 31, 2006, approximately 46% of our total estimated net proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. The 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 we own but do not operate, we may not be able to achieve any production from these properties in a timely manner.

As of December 31, 2006, approximately 11% of our PV-10 was attributable to properties for which we were not designated as the operator. As a result, the success and timing of our drilling and development activities on such nonoperated properties depend upon a number of factors, including:

the nature and timing of drilling and operational activities;

the timing and amount of capital expenditures;

the operators expertise and financial resources;

the approval of other participants in such properties; and

the selection of suitable technology.

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

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

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

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

One aspect of our business strategy calls for acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our bank credit facilities impose certain direct limitations on our ability to enter into mergers or combination transactions involving our company. Our bank credit facilities also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses. If we desire to engage in an acquisition that is otherwise

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prohibited by our bank credit facilities, we will be required to seek the consent of the lenders in accordance with the requirements of those facilities, which consent may be withheld by the lenders under our bank credit facilities in their discretion.

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

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

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

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

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

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

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

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

Because of the termination of our Transition Services Agreement with Mack Energy upon the completion of this offering, we must hire or relocate personnel to assume the daily operations of certain of our properties in the Permian Basin region of Southeast New Mexico. If we are not able to hire or relocate sufficient personnel to operate these properties, we may be forced to curtail operations in this area, which would result in a decrease in our rate of production and would have an adverse effect on our cash flow and results of operations. In addition, upon termination of the Transition Services Agreement, our production costs per unit of production in the field currently subject to the Transition Services Agreement may increase compared to our historical production costs per unit of production. This is primarily because certain arrangements pursuant to which oil and gas services and equipment are currently provided to us in this field will terminate in connection with the termination of the Transition Services Agreement, and we may be required to procure those services or equipment from alternative sources, which sources may charge more than we are currently paying for those services or equipment.

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

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

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;

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

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

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

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

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

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

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

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

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

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

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

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

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

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

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

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

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

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

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business and stock price.

As a public company, we will be required to evaluate our internal control systems to allow management to report on, and our independent auditors to audit, our internal control over financial reporting. As part of this process, we will be performing the system and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley

Act. We will first be required to comply with Section 404 for the year ending December 31, 2008.

We do not know when we will complete our evaluation, testing and remediation actions, if any, or the impact of the same on our operations. Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. Evaluating our internal control over financial reporting will likely involve substantial costs and take a significant amount of time to complete, which may distract our officers, directors and employees from the operation of our business. These efforts and any remedial actions we implement as a result of this evaluation may not ultimately be effective to maintain adequate internal control over financial reporting.

If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC. In addition, failure to comply with Section 404 or the report by us of a material weakness may cause investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

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

We now have, and after this offering will continue to have, a significant amount of indebtedness, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. As of March 31, 2007, our total debt was $505 million, and on an as adjusted basis (as if we had closed this offering and used the net proceeds as described in Use of proceeds on that date), our total debt would have been $ million. At March 31, 2007, our revolving credit facility bore interest at a rate of 6.87% per annum. Our second lien term loan facility currently bears interest at 9.10% per annum. Assuming our total debt outstanding as of March 31, 2007 was held constant throughout the three months ended March 31, 2007, if interest rates had been higher or lower by 1% per annum, interest expense for the three months ended March 31, 2007 would have increased or decreased by approximately $1.3 million. Our total borrowing capacity under our revolving credit facility is $375.0 million, of which $69.0 million was available as of March 31, 2007.

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;

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- increase our vulnerability to interest rate increases; and
- hinder our ability to adjust to rapidly changing economic and industry conditions.

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

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

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

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

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

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

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

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

Risks relating to the offering and our common stock

Certain stockholders shares are restricted from immediate resale but may be sold into the market in the near future. This could cause the market price of our common stock to drop significantly.

After this offering, we will have outstanding shares of common stock. Of these shares, the shares we and the selling stockholders are selling in this offering, or shares if the underwriters exercise their over-allotment option in full, will be freely tradeable without restriction under the Securities Act except for any shares purchased by one of our affiliates as defined in Rule 144 under the Securities Act. A total of shares, or shares if the underwriters exercise their over-allotment option in full, will be restricted securities (within the meaning of Rule 144 under the Securities Act) or subject to lock-up arrangements. In connection with this offering, we, our officers and directors and certain of our existing stockholders (including the selling stockholders) have entered into lock-up agreements under which we and they have agreed not to offer or sell any shares of common stock or securities convertible into or exchangeable or exercisable for shares of common stock for an initial period of 180 days from the date of this prospectus without the prior written consent of J.P. Morgan Securities Inc. and Banc of America Securities LLC, on behalf of the underwriters. J.P. Morgan Securities Inc. and Banc of America Securities LLC may, at any time and without notice, waive any of the terms of these lock-up agreements. See Underwriting for a description of these lock-up agreements. An aggregate of of these shares will become available for resale in the public market as shown in the chart below.

Number of shares	Date of eligibility for resale into public market
	No less than 180 days after the date of this prospectus (in accordance with lock-up agreements with the underwriters).
	Between 181 and 365 days after the date of this prospectus due to the requirements of the federal securities laws.

As soon as practicable after this offering, we intend to file one or more registration statements with the SEC on Form S-8 providing for the registration of shares of our common stock issued or reserved for issuance under our stock incentive plan. Subject to the exercise of unexercised options or the expiration or waiver of vesting conditions for restricted stock and the expiration of lock-ups we and certain of our stockholders have entered into, shares registered under these registration statements on Form S-8 will be available for resale immediately in the public market without restriction.

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Our management and directors and their affiliates will beneficially own, control or have substantial influence over a significant amount of our common stock, giving them a significant influence over our corporate transactions and other matters. Their interests may conflict with yours, and the concentration of ownership of our common stock by such stockholders will limit the influence of public stockholders.

Upon the closing of this offering, our management, directors and their respective affiliates, will beneficially own, control or have substantial influence over approximately % of our outstanding common stock. If these stockholders voted together as a group, they would have the ability to exert significant influence over our board of directors and its policies. These stockholders would, acting together, be able to significantly influence the outcome of stockholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our certificate of incorporation or bylaws and possible mergers, corporate control contests and other significant corporate transactions. This concentration of ownership may have the effect of delaying, deferring or preventing a change in control, a merger, consolidation, takeover or other business combination. This concentration of ownership could also discourage a potential acquiror from making a tender offer or otherwise attempting to obtain control of us, which could in turn have an adverse effect on the market price of our common stock.

Purchasers of common stock will experience immediate and substantial dilution.

Based on an assumed initial public offering price of $ per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the net tangible book value per share of common stock from the initial public offering price, and our pro forma net tangible book value as of March 31, 2007, after giving effect to this offering, would be $ per share. You will incur further dilution if outstanding options to purchase common stock are exercised. In addition, our certificate of incorporation allows us to issue significant numbers of additional shares. Please read Dilution for a description of the calculation of net tangible book value.

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

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

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;
- limitations on the removal of directors;
- the prohibition of stockholder action by written consent; and

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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.

Please read Description of capital stock Anti-takeover provisions of our certificate of incorporation and bylaws for more information about these provisions.

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

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. The terms of our existing bank credit facilities restrict the payment of dividends without the prior written consent of the lenders. Investors 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. Investors seeking cash dividends should not purchase our common stock.

There has been no active trading market for our common stock, and an active trading market may not develop.

Prior to this offering, there has been no public market for our common stock. We intend to apply to list our common stock for trading on the New York Stock Exchange. We do not know if an active trading market will develop for our common stock or how the common stock will trade in the future, which may make it more difficult for you to sell your shares. Negotiations among the underwriters, certain of the selling stockholders and us will determine the initial public offering price, which may not be indicative of the price at which our common stock will trade following the closing of this offering. You may not be able to resell your shares at or above the initial public offering price.

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. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into our common stock. Any of these events may dilute your ownership interest in our company and have an adverse impact on the price of our common stock.

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

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The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934 and the requirements of the Sarbanes-Oxley Act, may strain our resources and increase our costs. We may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of the time of our board of directors and management and will increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- involve and retain to a greater degree outside counsel and accountants in the above activities;
- establish an investor relations function; and
- attract and retain qualified personnel for compliance.

In addition, we also expect that being a public company subject to these rules and regulations will require us to modify our director and officer liability insurance, and we may be required to accept reduced coverage or to incur substantially higher costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, as well as qualified executive officers.

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Cautionary statement regarding forward-looking statements

This prospectus contains forward-looking statements 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 prospectus, 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 prospectus, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project and similar intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

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

You should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this prospectus. We do not undertake any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this prospectus or to reflect the occurrence of unanticipated events, unless the securities laws require us to do so.

Although we believe that our plans, objectives, expectations and intentions reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that they will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk factors and Management s discussion and analysis of financial condition and results of operations and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Use of proceeds

We estimate that our net proceeds from this offering will be approximately $ million, assuming an initial public offering price of $ per share and after deducting underwriting discounts and commissions and estimated offering expenses. A $1.00 increase (decrease) in the assumed initial public offering price per share would increase (decrease) the net proceeds to us from this offering by $ million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting underwriting discounts and estimated offering expenses payable by us. We intend to use all of the net proceeds we receive from this offering to repay a portion of our outstanding indebtedness under our second lien term loan facility, our revolving credit facility or a combination of the foregoing. Under the terms of our second lien term loan facility, we are obligated to use not less than 50% of our net proceeds to repay a portion of our outstanding indebtedness under our second lien term loan facility. Currently, we expect to use half of the net proceeds to repay a portion of our outstanding indebtedness under our second lien term loan facility and the remaining half of the net proceeds to repay a portion of our outstanding indebtedness under our revolving credit facility. We may, however, allocate a greater portion of the net proceeds to repay a portion of our outstanding indebtedness under our second lien term loan facility based on the relative interest rates of our revolving credit facility and our second lien term loan facility and our anticipated capital needs at the time of closing of this offering. We will not receive any of the net proceeds from the sale of shares of common stock by the selling stockholders. See Principal and selling stockholders.

Our revolving credit facility bore interest at 6.87% per annum as of March 31, 2007 and matures on February 24, 2010. We incurred borrowings of approximately $421.0 million under our revolving credit facility in connection with the combination transaction in February 2006 to pay the cash purchase price of $400.0 million to the Chase Group, $15.9 million to repay the balance on the prior revolving credit facility of Concho Equity Holdings Corp. and approximately $5.1 million for bank fees and legal costs associated with our revolving credit facility. We also incurred borrowings of approximately $8.9 million in May 2006 in connection with the purchase of additional working interests in the Chase Group Properties pursuant to the combination transaction from persons associated with the Chase Group. The remaining borrowings under our revolving credit facility were used for working capital and to fund a portion of our exploration and development drilling program. Our second lien term loan facility currently bears interest at 9.10% per annum and matures on March 27, 2012. We used the borrowings from our second lien term loan facility of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes.

Certain affiliates of the underwriters to this offering are lenders under our second lien term loan facility and our revolving credit facility and will receive a portion of the net proceeds we receive from this offering based on the amount of the loans they have extended under these bank credit facilities. Banc of America Securities LLC is the lead arranger and book manager under our second lien term loan facility. In addition, each of BNP Paribas Securities Corp. and Merrill Lynch, Pierce, Fenner & Smith Incorporated has an affiliate that is a lender and/or agent under our second lien term loan facility. In addition, under our revolving credit facility, JPMorgan Chase Bank, N.A. is the administrative agent, Bank of America, N.A. is the syndication agent and each of Wachovia Bank, National Association and BNP Paribas is a documentation agent. Each of these is a lender under our revolving credit facility and is an affiliate of one of the underwriters of this offering. Please read Underwriting.

Dividend policy

Following this offering of our common stock, we do not currently anticipate paying any cash dividends on our common stock. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. We are also currently prohibited from paying dividends by our bank credit facilities.

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Capitalization

The following table shows our cash and cash equivalents and our total capitalization as of March 31, 2007 on an actual basis and on an as adjusted basis to reflect the following events:

- the repayment by our executive officers of certain loans made by our company to our executive officers prior to the filing of the registration statement of which this prospectus is a part; and

- the closing of this offering and the application of the net proceeds from this offering as described under Use of proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should read this information in conjunction with these consolidated financial statements and Management s discussion and analysis of financial condition and results of operations.

	As of March 31, 2007	
(in thousands)	**Actual**	**As adjusted[1]**
Cash and cash equivalents	$ 2,573	$
Long-term debt, including current maturities	$ 505,000	$
Stockholders equity:		
Series A preferred stock, $.01 par value; 30,000,000 shares authorized, zero shares issued and outstanding, actual and as adjusted		
Preferred stock, $.001 par value; 10,000,000 shares authorized, zero shares issued and outstanding, actual and as adjusted		
Common stock, $.001 par value; 300,000,000 shares authorized, 118,185,563 shares issued and outstanding, actual and shares issued and outstanding as adjusted[2]	118	
Additional paid-in capital	576,155	
Notes receivable from officers and employees	(13,028)	
Retained earnings	16,734	
Accumulated other comprehensive loss, net of taxes	(5,188)	
Total stockholders equity	574,791	
Total capitalization	$ 1,079,791	$

(1) A $1.00 increase (decrease) in the assumed initial public offering price per share would decrease (increase) long-term debt, including current maturities, by $ million and increase (decrease) each of additional paid-in capital, total stockholders equity and total capitalization by $ million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same.

(2) The number of shares of common stock issued and outstanding on an actual and an as adjusted basis includes shares of common stock outstanding and awards of restricted stock, but does not include shares of common stock subject to outstanding options.

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Dilution

Purchasers of common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Net tangible book value per share represents the amount of our total tangible assets less our total liabilities, divided by the number of shares of common stock that will be outstanding. At March 31, 2007, we had a net tangible book value of $569.4 million, or $4.82 per share. After giving effect to the sale by us of shares of common stock in this offering at an assumed initial public offering price of $ per share and after the deduction of underwriting discounts and estimated offering expenses, the as adjusted net tangible book value at March 31, 2007, would have been $ million, or $ per share. This represents an immediate increase in such net tangible book value of $ per share to existing stockholders and an immediate and substantial dilution of $ per share to new investors purchasing common stock in this offering. The following table illustrates this per share dilution:

Assumed initial public offering price per share		$
Net tangible book value per share as of March 31, 2007	$	
Increase per share attributable to the offering	$	
As adjusted net tangible book value per share after the offering		$
Dilution in as adjusted net tangible book value per share to new investors		$

A $1.00 increase (decrease) in the assumed initial public offering price per share would increase (decrease) our as adjusted net tangible book value by $ million, would increase (decrease) our net tangible book value per share by $ per share and would increase (decrease) the dilution in as adjusted net tangible book value to new investors in this offering by $ per share, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same.

The following table summarizes, on an as adjusted basis set forth above as of March 31, 2007, the total number of shares of common stock owned by existing stockholders and to be owned by new investors, the total consideration paid and the average price per share paid by our existing stockholders and to be paid by new investors in this offering at $, the mid-point of the range of the initial public offering prices set forth on the cover of this prospectus, calculated before deduction of estimated underwriting discounts.

	Shares acquired[1]		Total consideration[2]		Average price paid per share
	Number	**Percent**	**Amount**	**Percent**	
Existing stockholders		%	$	%	$
New investors					
Total		100.0%	$	100.0%	

(1) The number of shares disclosed for the existing stockholders includes shares being sold by the selling stockholders in this offering. The number of shares disclosed for the new investors does not include the shares being purchased by the new investors from the selling stockholders in this offering.

(2) A $1.00 increase (decrease) in the assumed initial public offering price per share would increase (decrease) total consideration paid by new investors by $ million, or increase (decrease) the percent of total consideration paid by new investors to %, assuming the number of shares offered by us, as set forth on the cover of this prospectus, remains the same.

Selected historical and pro forma consolidated financial information

This section presents our selected historical and pro forma 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 prospectus. You should also read the pro forma information together with the unaudited pro forma combined financial statements and related notes included in this prospectus.

Selected historical and pro forma financial information for Concho Resources Inc.

The following table shows selected historical financial data related to Concho Resources Inc. (as the accounting successor to Concho Equity Holdings Corp.), combined financial data of the Chase Group Properties and unaudited pro forma financial data of Concho Resources as of and for the year ended December 31, 2006. 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 Resources such that Concho Equity Holdings Corp. is now our wholly owned subsidiary.

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

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

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

On February 27, 2006, the initial closing of the combination transaction occurred. Pursuant to the combination transaction, Concho Resources acquired the Chase Group Properties for approximately 70 million shares of common stock and approximately $409 million in cash.

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

The historical financial data for the Chase Group Properties for the years ended December 31, 2003, 2004 and 2005 are derived from the audited financial statements of the Chase Group Properties. The historical financial data for the Chase Group Properties for the year ended December 31, 2002 is derived from the unaudited financial statements of the Chase Group Properties. The historical financial data for Concho Resources for the period from inception (April 21, 2004) through December 31, 2004, and for the years ended December 31, 2005 and 2006, are derived from the audited financial statements of Concho Resources. The historical financial data for Concho Resources for the three months ended March 31, 2006 and 2007, are derived from the unaudited financial statements of Concho Resources.

The pro forma financial data for the year ended December 31, 2006 set forth in the following table is derived from the unaudited pro forma financial statements of Concho Resources included in this prospectus. The pro forma statement of operations has been prepared as if the closing of the combination transaction had taken place as of January 1, 2006.

Our balance sheet data as of March 31, 2007, as adjusted, gives effect to the following transactions:

- the issuance by us of shares of common stock in this offering;
- the repayment by our executive officers of certain loans made by our company to our executive officers prior to the filing of the registration statement of which this prospectus is a part; and
- the repayment of a portion of our outstanding indebtedness using proceeds from this offering as described in Use of proceeds.

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The following table includes the non-GAAP financial measure EBITDA. For a definition of this measure and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with generally accepted accounting principles, which we refer to as GAAP, please read Prospectus summary Non-GAAP financial measures and reconciliations.

	Chase Group Properties				Concho Resou				
	Years ended December 31,				Inception (April 21, 2004) through December 31,	Years ended December 31,		Pro forma year ended December 31,	Thre ended M
ds, except amounts)	2002	2003	2004	2005	2004	2005	2006	2006	2006
	(unaudited)							(unaudited)	(unaudited)
of operations									
revenues:									
	$ 59,881	$ 62,016	$ 66,529	$ 73,132	$ 1,851	$ 31,621	$ 131,773	$ 145,713	$ 16,404
sales	23,870	41,486	41,247	46,546	1,771	23,315	66,517	74,033	9,248
ting revenues	83,751	103,502	107,776	119,678	3,622	54,936	198,290	219,746	25,652
costs and									
production	10,386	9,868	11,762	12,979	512	10,923	22,060	24,456	3,929
production	6,928	8,815	9,202	10,298	234	3,712	15,762	17,602	1,981
and nts	900	2,116	179		1,850	2,666	5,612	5,612	906
n, depletion and	16,239	19,643	20,459	19,092	963	11,574	61,009	66,520	7,260
s of proved oil perties	1,587	2,065	3,233	194		2,295	9,891	9,892	105
illing d rigs									
d administrative	1,128	1,246	1,387	1,702	3,086	8,055	12,577	12,861	2,437
d compensation					1,128	3,252	9,144	9,144	6,622
portion of cash s						1,148	(1,193)	(1,193)	786
on derivatives ted as hedges	3,379	576	7,936	1,062	(684)	5,001			

ting costs and	40,547	44,329	54,158	45,327	7,089	48,626	134,862	144,894	24,026	
ss) from	43,204	59,173	53,618	74,351	(3,467)	6,310	63,428	74,852	1,626	
me (expense):										
ense					(272)	(3,096)	(30,567)	(35,790)	(3,610)	
					168	779	1,186	1,186	303	
expense					(104)	(2,317)	(29,381)	(34,604)	(3,307)	
ss) before es	43,204	59,173	53,618	74,351	(3,571)	3,993	34,047	40,248	(1,681)	
(expense)					915	(2,039)	(14,379)	(16,797)	253	
e (loss)	$ 43,204	$ 59,173	$ 53,618	$ 74,351	(2,656)	1,954	19,668	23,451	(1,428)	
ock dividends					(804)	(4,766)	(1,244)		(1,146)	
duced of preferred							11,601		11,601	
e (loss) to common ers					$ (3,460)	$ (2,812)	$ 30,025	$ 23,451	$ 9,027	$
' (unaudited)			$ 74,077	$ 93,443	$ (2,336)	$ 18,663	$ 125,623	$ 142,558	$ 9,189	$
ings (loss) per										

(loss) per share	$ (1.74)	$ (0.35)	$ 0.32	$ 0.22	$ 0.19	$
l in basic oss) per share	1,987	8,117	94,575	108,335	47,951	
rnings (loss)						
(loss) per share	$ (1.74)	$ (0.35)	$ 0.30	$ 0.20	$ 0.17	$
l in diluted oss) per share	1,987	8,117	101,458	115,412	53,005	

	Chase Group Properties				Concho Resources Inc.			
	Years ended December 31,			Inception (April 21, 2004) through December 31,	Years ended December 31,		Three months ended March 31,	
n thousands)	2003	2004	2005	2004	2005	2006	2006	2007
							(unaudited)	(unaudited)
ther financial ata:								
et cash provided by ised in) operations	$ 84,264	$ 84,202	$ 93,162	$ (2,193)	$ 25,070	$ 112,181	$ 11,615	$ 31,049
et cash provided by ised in) investing	(31,823)	(30,045)	(35,611)	(122,473)	(61,902)	(596,852)	(447,018)	(36,564
et cash provided by ised in) financing	(52,441)	(54,157)	(57,551)	125,322	45,358	476,611	426,221	6,966
apital expenditures	29,449	25,451	32,352	116,880	72,758	1,226,180	1,039,414	27,430

	Chase Group Properties				Concho Resources Inc.				
			As of December 31,			As of December 31,		As of March 31,	As adjusted as of March 31,
(in thousands)	2002	2003	2004	2005	2004	2005	2006	2007	2007(2)
	(unaudited)	(unaudited)						(unaudited)	(unaudited)
Balance sheet data:									
Cash and cash equivalents	$	$	$	$	$ 656	$ 9,182	$ 1,122	$ 2,573	$
Property and equipment, net	126,956	133,547	135,568	149,042	115,455	170,583	1,320,655	1,327,095	1,327,095
Total assets	135,973	141,860	145,100	161,792	130,717	232,385	1,390,072	1,380,339	
Long-term debt, including current maturities					53,000	72,000	495,500	505,000	
Stockholders equity/net investment	127,821	134,554	134,014	150,814	71,710	109,670	575,156	574,791	

(1) EBITDA is defined as income before accounting changes, plus (1) interest, the amortization of related debt issuance costs and other financial costs, net of capitalized interest, (2) federal and state income taxes and (3) depreciation, depletion and accretion. See Prospectus summary Non-GAAP financial measures and reconciliations.

(2) A $1.00 increase (decrease) in the assumed initial public offering price per share would decrease (increase) long-term debt, including current maturities by $ and would increase (decrease) stockholders equity by $, assuming the number of shares offered by us set forth on the cover page of this prospectus remains the same and after deducting underwriting discounts and estimated offering expenses payable by us.

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Selected historical financial and operating information for Lowe Properties

The selected financial data for the Lowe Properties for the years ended December 31, 2002 and 2003 and for the period from January 1, 2004 through November 30, 2004 were derived from the audited and unaudited statements of revenue and direct operating expenses of the Lowe Properties included in this prospectus and information provided by the seller.

Statement of revenues and direct operating expenses data: (in thousands)	Years ended December 31, 2002	Years ended December 31, 2003	Period from January 1, 2004 through November 30, 2004
	(unaudited)		
Revenues	$ 25,753	$ 32,371	$ 34,663
Direct operating expenses:			
Lease operating expense	7,519	6,652	6,983
Production tax expense	1,597	2,023	2,159
Other expenses		435	461
Total direct operating expenses	9,116	9,110	9,603
Revenues in excess of direct operating expenses	$ 16,637	$ 23,261	$ 25,060

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 prospectus.

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

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of producing oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We have also acquired significant acreage positions in the Permian Basin of Southeast New Mexico, the Central Basin Platform, the Delaware Basin and the Val Verde Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas, covering unconventional emerging resource plays, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. Crude oil comprised 57% of our 467 Bcfe of estimated net proved reserves as of December 31, 2006, and 59% of our 23.3 Bcfe of production for the year ended December 31, 2006. Crude oil comprised 59% of our 7.2 Bcfe of production for the three months ended March 31, 2007. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 89% of our PV-10 and 48% of our 1,921 gross wells as of December 31, 2006 and 48% of our 1,927 gross wells as of March 31, 2007. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

On February 24, 2006, we entered into a combination agreement in which we agreed to purchase certain oil and gas properties owned by Chase Oil Corporation, Caza Energy LLC and certain other individual 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. As a result of the initial closing of the combination transaction, the members of the Chase Group that sold their working interests to us at the initial closing of the combination transaction received 69,366,627 shares of our common stock and approximately $400 million in cash, and the former shareholders of Concho Equity Holdings Corp. that were a party to the combination agreement received 47,535,346 shares of our common stock. In addition, certain options held by our employees to purchase preferred and common stock of Concho Equity Holdings Corp. were converted into options to purchase 4,698,331 shares of our common stock. The oil and gas properties contributed to us by the Chase Group (which we refer to as the Chase Group Properties) represent approximately 76% of our PV-10 as of December 31, 2006. The executive officers of Concho Equity Holdings Corp. became the executive officers of our company in connection with the initial closing of the combination transaction. We have accounted for the combination transaction as a reorganization of our company, such that Concho Equity Holdings Corp. is now our wholly owned subsidiary, and a simultaneous acquisition by our company of the assets contributed by the Chase Group.

We agreed in the combination agreement to offer to acquire additional interests in the Chase Group Properties from persons associated with the Chase Group. In May 2006, we acquired certain of such interests from ten of such persons in exchange for an aggregate consideration of 222,645 shares of our common stock and $8.9 million in cash. In April 2007, we offered to acquire the remainder of such interests from an additional nine persons in exchange for, at the respective seller s option, shares of our common stock or cash, or any combination thereof, aggregating a total purchase offer of $906,000. Terms concerning the exchange of such interests for shares of our common stock were the same as the terms in the combination agreement. During April 2007, we acquired these interests for $255,000 in cash and 108,457 shares of our common stock.

In addition, because certain employee stockholders of Concho Equity Holdings Corp. were not confirmed to have been accredited investors at the time of the combination transaction, their 254,621 units, consisting of one preferred and one common share of Concho Equity Holdings Corp., could not be immediately exchanged for our common shares. On April 16, 2007, these remaining shares of Concho Equity Holdings Corp. were exchanged for 636,555 shares of our common stock. As a result, Concho Equity Holdings Corp. is now our wholly owned subsidiary. The common and preferred shares of Concho Equity Holdings Corp. which were outstanding between February 27, 2006 and April 16, 2007 have been treated as exchangeable for and equivalent to shares of our common stock in our consolidated financial statements.

Factors that significantly affect our results

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

We generally hedge a portion of our expected future oil and natural gas production to reduce our exposure to fluctuations in commodity price. See Liquidity and capital resources Hedging for a discussion of our hedging and hedge positions.

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

Items impacting comparability of our financial results

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

Combination transaction

We were formed in February 2006 as a result of the combination transaction between Concho Equity Holdings Corp. and the Chase Group.

Concho Equity Holdings Corp. is our predecessor for accounting purposes. As a result, our historical financial statements prior to February 27, 2006, are the financial statements of Concho Equity Holdings Corp. Concho Equity Holdings Corp. was formed on April 21, 2004, and did not own any material assets and did not conduct substantial operations other than organizational activities until it acquired the Lowe Properties on December 7, 2004. For a discussion of the results of operations of Concho Resources (as the accounting successor to Concho Equity Holdings Corp.), please read Results of operations of Concho Resources. The financial statements of Concho Resources (as the accounting successor to Concho Equity Holdings Corp.), together with the notes thereto, are also included in this prospectus.

As of December 31, 2006, approximately 76% of our PV-10 was attributable to the properties contributed to us by the Chase Group in the combination transaction. For a discussion of the results of operations of the Chase Group Properties, please read Results of operations of the Chase Group Properties. The combined financial statements of the Chase Group Properties, together with the notes thereto, are also included in this prospectus.

Additional indebtedness and other expenses

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

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

- we incurred approximately $405 million of new indebtedness upon the initial closing of the combination transaction;

- we entered into a $200.0 million second lien term loan facility on March 27, 2007, from which we received proceeds of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes; and

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

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Curtailment of drilling

We determined in January 2007 to reduce our drilling activities for the first three months of 2007. This determination was due to a decline in oil and natural gas prices in January 2007 compared to such prices in the fourth quarter of 2006, the costs of goods and services necessary to complete our drilling activities and the resulting effect of these circumstances on our expected cash flow for the three months ended March 31, 2007. In addition, we determined to reduce our drilling activities and curtail capital expenditures until we were able to complete our second lien term loan facility in March 2007 in order to preserve liquidity. Also due to the reduced drilling activities described above, we recorded an expense in the first quarter of 2007 of approximately $3.4 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. Approximately $3.0 million of this amount was paid to Silver Oak Drilling, LLC, which is an affiliate of the Chase Group. We resumed our planned drilling activities in April 2007, and we believe we will spend our planned 2007 exploration and development budget of approximately $154.0 million during 2007.

Public company expenses

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

Results of operations of Concho Resources Inc.

The following table presents selected financial and operating information of Concho Resources Inc. (as successor to Concho Equity Holdings Corp.) for the period of inception (April 21,

2004) through December 31, 2004, for the years ended December 31, 2005 and 2006 and for the three months ended March 31, 2006 and 2007:

(in thousands, except price data)	Inception (April 21, 2004) through December 31, 2004	Years ended December 31, 2005	2006	Three months ended March 31, 2006 (unaudited)	2007 (unaudited)
Oil sales	$ 1,851	$ 31,621	$ 131,773	$ 16,404	$ 39,371
Natural gas sales	1,771	23,315	66,517	9,248	20,975
Total operating revenues	3,622	54,936	198,290	25,652	60,346
Operating costs and expenses	7,089	48,626	134,862	24,026	41,938
Interest, net and other revenue	104	2,317	29,381	3,307	10,410
Income (loss) before income taxes	(3,571)	3,993	34,047	(1,681)	7,998
Income tax (expense) benefit	915	(2,039)	(14,379)	253	(3,375)
Net income (loss)	$ (2,656)	$ 1,954	$ 19,668	$ (1,428)	$ 4,623
Production volumes (unaudited):					
Oil (MBbl)	44.7	599.0	2,294.8	312.3	708.9
Natural gas (MMcf)	290.7	3,403.8	9,506.8	1,414.1	2,952.2
Natural gas equivalent (MMcfe)	559.1	6,997.7	23,275.4	3,288.1	7,205.5
Average prices (unaudited):					
Oil, without hedges ($/Bbl)	$ 41.37	$ 54.71	$ 60.47	$ 56.73	$ 54.09
Oil, with hedges ($/Bbl)	41.37	52.79	57.42	52.52	55.54
Natural gas, without hedges ($/Mcf)	6.09	6.99	6.87	6.76	7.06
Natural gas, with hedges ($/Mcf)	6.09	6.85	7.00	6.54	7.10
Natural gas equivalent, without hedges ($/Mcfe)	6.48	8.08	8.77	8.29	8.21
Natural gas equivalent, with hedges ($/Mcfe)	6.48	7.85	8.52	7.80	8.37

Three months ended March 31, 2006, compared to three months ended March 31, 2007

Oil and gas revenues. Revenue from oil and gas operations increased by $34.6 million (135%) from $25.7 million for the three months ended March 31, 2006 to $60.3 million for the three months ended March 31, 2007. 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. Total production increased 3,918 MMcfe (119%) from 3,288 MMcfe for the three months ended March 31, 2006 to 7,206 MMcfe for the three months ended March 31, 2007. The increases in revenue and production attributable to the Chase Group Properties between 2006 and 2007 were $26.8 million and 3,281 MMcfe, respectively. In addition, average realized oil prices (after giving effect to hedging activities) increased 6% from $52.52 per Bbl during the three months ended March 31, 2006 to $55.54 per Bbl during the three months ended March 31, 2007; average realized natural gas prices (after giving effect to hedging activities) increased 9% from $6.54 per Mcf during the three months ended March 31, 2006 to $7.10 per Mcf during the three months ended March 31, 2007; and average realized natural gas equivalent prices (after giving effect to hedging activities) increased 7% from $7.80 per Mcfe during the three months ended March 31, 2006 to $8.37 per Mcfe during the three months ended March 31, 2007.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. During the three months ended March 31, 2006, our commodity price hedges decreased oil revenues by $1.3 million ($4.21 per Bbl) and decreased gas revenues by $0.3 million ($0.22 per Mcf). During the three months ended March 31, 2007, our commodity price hedges increased oil revenues by $1.0 million ($1.45 per Bbl) and increased gas revenues by $0.1 million ($0.05 per Mcf).

The effect of the commodity price hedges in increasing oil revenues during the three months ended March 31, 2007 as compared to reducing oil revenues during the three months ended March 31, 2006 was the result of (1) increased hedged volumes from 63,000 Bbls in 2006 to 265,500 Bbls in 2007 and (2) a decrease in the market price of NYMEX crude oil from an average of $63.38 per Bbl in 2006 to $58.32 per Bbl in 2007. The effect of the commodity price hedges in increasing gas revenues during the three months ended March 31, 2007 as compared to reducing gas revenues during the three months ended March 31, 2006 was the result of (1) increased hedged volumes from 360,000 MMBtus in 2006 to 1,440,000 MMBtus in 2007 and (2) a decrease in the reference market price of natural gas from an average of $7.16 per MMBtu in 2006 to $6.32 per MMBtu in 2007.

Production expenses. Production expenses (including production taxes) increased $6.0 million (102%) from $5.9 million ($1.80 per Mcfe) to $11.9 million ($1.66 per Mcfe) for the three months ended March 31, 2006 and 2007, respectively. The increase in production expenses are due to two sources: (1) production expenses associated with the Chase Group Properties acquired in February 2006 of approximately $4.3 million and (2) costs associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities. Lease operating expenses and workover costs comprised approximately 66% and 61% of production expenses for the three months ended March 31, 2006 and 2007, respectively. These costs per unit of production decreased 16% from $1.19 per Mcfe during the three months ended March 31, 2006 to $1.01 per Mcfe during the three months ended March 31, 2007. This is because the Chase Group Properties are, on average, less expensive to operate than the properties we operated prior to the combination transaction. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 6% and 9% of lease operating expenses for the three months ended March 31, 2006 and 2007, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 34% and 39% of production expenses during the three months ended March 31, 2006 and 2007, respectively. Production taxes per unit of production increased 8% from $0.60 per Mcfe during the three months ended March 31, 2006 to $0.65 per Mcfe during the three months ended March 31, 2007. This increase was primarily due to an increase in average realized natural gas equivalent prices.

Depreciation and depletion expense. Depreciation and depletion expense increased $12.2 million from $7.2 million ($2.20 per Mcfe) to $19.4 million ($2.70 per Mcfe) for the three months ended March 31, 2006 and 2007, respectively. The increase in depreciation and depletion expense and expense per Mcfe was primarily due to the acquisition of the Chase Group Properties and related acquisition costs associated with the combination transaction.

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Approximately $9.1 million of the increase in depreciation and depletion expense during the three months ended March 31, 2007 was attributable to the acquisition of the Chase Group Properties.

Impairment of oil and gas properties. In accordance with Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, 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 three months ended March 31, 2006, we recognized a non-cash charge against earnings of $0.1 million related to our proved oil and gas properties. For the three months ended March 31, 2007, we recognized a non-cash charge against earnings of $1.1 million related to our proved oil and gas properties. Of this amount, $0.2 million was related to the Chase Group Properties.

Contract drilling fees stacked rigs. As discussed above under Items impacting comparability of our financial results Curtailment of drilling, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the three months ended March 31, 2007 of approximately $3.4 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. We resumed our planned drilling activities in April 2007.

General and administrative expenses. General and administrative expenses decreased $4.8 million (53%) from $9.1 million ($2.76 per Mcfe) to $4.3 million ($0.60 per Mcfe) for the three months ended March 31, 2006 and 2007, respectively. Excluding non-cash stock-based compensation of $6.6 million during the three months ended March 31, 2006 and $0.8 million during the three months ended March 31, 2007, general and administrative expenses increased $1.0 million (42%) from $2.5 million ($0.74 per Mcfe) to $3.5 million ($0.48 per Mcfe) for the three months ended March 31, 2006 and 2007, respectively. The increase in general and administrative expense during 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. We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $0.2 million and $0.4 million during the three months ended March 31, 2006 and 2007, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Interest expense. Interest expense increased $7.1 million from $3.6 million to $10.7 million for the three months ended March 31, 2006 and 2007, respectively. The weighted average interest rate for the three months ended March 31, 2006 and 2007 was 7.1% and 7.9%, respectively. The weighted average debt outstanding during the three months ended March 31, 2006 and 2007 was approximately $196.8 million and $496.4 million, respectively. The increase in interest expense was due to the increase in overall debt outstanding and an increase in interest rates. The increase in weighted average debt outstanding during the three months ended March 31, 2007 was primarily due to our borrowing under our revolving credit facility to fund our drilling activities.

Income tax provisions (benefits). We recorded an income tax benefit of $0.3 million and income tax expense of $3.4 million for the three months ended March 31, 2006 and 2007, respectively. The income tax benefit was due to the loss reported during the three months ended March 31, 2006, and the income tax expense was due to the income reported during the three months ended March 31, 2007, respectively.

We had a net deferred tax liability of $241.7 million and $241.0 million at December 31, 2006 and March 31, 2007, respectively. The net liability balance is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006. The net change is due to 2007 intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principals in the United States of America, partially offset by an increase in deferred hedge losses.

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

Oil and gas revenues. Revenue from oil and gas operations increased by $143.4 million (261%) from $54.9 million for the year ended December 31, 2005 to $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 2005 and 2006. Total production increased 16,277 MMcfe (233%) from 6,998 MMcfe for the year ended December 31, 2005 to 23,275 MMcfe for the year ended December 31, 2006. The increases in revenue and production attributable to the Chase Group Properties between 2005 and 2006 were $136.2 million and 11,747 MMcfe, respectively. In addition, average realized oil prices (after giving effect to hedging activities) increased 9% from $52.79 per Bbl in 2005 to $57.42 per Bbl in 2006, average realized natural gas prices (after giving effect to hedging activities) increased 2% from $6.85 per Mcf in 2005 to $7.00 per Mcf in 2006 and average realized natural gas equivalent prices (after giving effect to hedging activities) increased 9% from $7.85 per Mcfe in 2005 to $8.52 per Mcfe in 2006.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. During 2005, our commodity price hedges decreased oil revenues by $1.2 million ($1.92 per Bbl) and decreased gas revenues by $0.5 million ($0.14 per Mcf). During 2006, our commodity price hedges decreased oil revenues by $7.0 million ($3.05 per Bbl) and increased gas revenues by $1.2 million ($0.13 per Mcf).

The increased effect of the commodity price hedges in reducing oil revenues during 2006 as compared to 2005 was the result of (1) increased hedged volumes from 292,000 Bbls in 2005 to 1,080,500 Bbls in 2006 and (2) an increase in the market price of NYMEX crude oil from an average of $56.57 per Bbl in 2005 to $66.21 per Bbl in 2006. The effect of the commodity price hedges in increasing gas revenues during 2006 as compared to reducing gas revenues in 2005 was the result of (1) increased hedged volumes from 1,642,500 MMBtus in 2005 to 5,447,500 MMBtus in 2006 and (2) a decrease in the reference market price of natural gas from an average of $7.17 per MMBtu in 2005 to $6.05 per MMBtu in 2006.

Production expenses Production expenses (including production taxes) increased $23.2 million (159%) from $14.6 million ($2.09 per Mcfe) to $37.8 million ($1.62 per Mcfe) for the years ended December 31, 2005 and 2006, respectively. The increase in production expenses are due to two sources: (1) production costs associated with the Chase Group Properties acquired in February 2006 of approximately $20.2 million and (2) costs associated with new wells that were successfully completed in 2005 and 2006 as a result of our drilling activities. Lease operating expenses and workover costs comprised approximately 75% and 58% of production expenses for 2005 and 2006, respectively. These costs per unit of production decreased 39% from $1.56 per Mcfe in 2005 to $0.95 per Mcfe in 2006. This is because the Chase Group Properties are, on average, less expensive to operate than the properties we operated prior to the combination transaction. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 9% and 5% of lease operating expenses for 2005 and 2006, respectively.

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

Exploration and abandonments / geological and geophysical costs. Exploration and abandonments / geological and geophysical costs increased by $2.9 million from $2.7 million during 2005 to $5.6 million during 2006. The exploration and abandonments / geological and geophysical costs during 2005 consisted of $1.4 million of exploratory dry hole costs and $1.3 million of geological and geophysical costs. The exploratory dry hole costs during 2005 were attributable to one exploratory dry hole in each of Eddy and Lea Counties, New Mexico that we operated and to one exploratory dry hole in Zapata County, Texas operated by another company. The geological and geophysical costs for 2005 primarily consisted of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis. The exploration and abandonments / geological and geophysical costs during 2006 consisted of $3.4 million of exploratory dry hole costs and $2.2 million of geological and geophysical costs. The exploratory dry hole costs during 2006 were attributable to one exploratory dry hole in Gaines County, Texas that we operated and one exploratory dry hole in Val Verde County, Texas operated by another company. The geological and geophysical costs for 2006 primarily consisted of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis.

Depreciation and depletion expense. Total depreciation and depletion expense increased $49.2 million (428%) from $11.5 million ($1.64 per Mcfe) to $60.7 million ($2.61 per Mcfe) for the years ended December 31, 2005 and 2006, respectively. The increase in total expense and expense per Mcfe was primarily due to the acquisition of the Chase Group Properties and related acquisition costs associated with the combination transaction. Approximately $30.7 million of the increase in depreciation and depletion expense for 2006 was attributable to the acquisition of the Chase Group Properties.

Impairment of oil and gas properties. In accordance with Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, 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 2005, we recognized a non-cash charge against earnings of $2.3 million related to our proved oil and gas properties. For the year ended December 31, 2006, we recognized a non-cash charge against earnings of $9.9 million related to our proved oil and gas properties. Of this amount, $0.1 million was related to the Chase Group Properties.

General and administrative expenses. General and administrative expenses increased $10.4 million (92%) from $11.3 million ($1.62 per Mcfe) to $21.7 million ($0.93 per Mcfe) for the years ended December 31, 2005 and 2006 respectively. Excluding non-cash stock-based compensation of $3.3 million in 2005 and $9.1 million in 2006, general and administrative expenses increased $4.5 million (56%) from $8.1 million ($1.15 per Mcfe) to $12.6 million ($0.54 per Mcfe) for the years ended December 31, 2005 and 2006, respectively. The increase in general and administrative expense during 2006 was primarily because of the hiring of additional staff and an increase in professional fees related to the combination transaction and other activities of our company. We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $0.6 million and $0.8 million during the years ended December 31, 2005 and 2006, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Interest expense. Interest expense increased $27.5 million from $3.1 million to $30.6 million for the years ended December 31, 2005 and 2006, respectively. The weighted average interest rate for the years ended December 31, 2005 and 2006 was 5.5% and 7.5%, respectively. The weighted average debt outstanding during 2005 and 2006 was approximately $59 million and $407 million, respectively. The increase in interest expense was due to the increase in overall debt outstanding and the increase in interest rates. The increase in weighted average debt outstanding during 2006 was primarily due to our borrowing under our revolving credit facility on February 27, 2006 to fund the cash payment due as part of the combination transaction, to repay the Concho Equity Holdings Corp. credit facility, and to pay bank and legal fees. The increase in weighted average debt outstanding was also due to our borrowing $40 million under our prior second lien term loan facility on July 6, 2006 to reduce the amount outstanding under our revolving credit facility by $32.1 million, with the remaining $7.9 million used for general corporate purposes.

Other, net. Interest and other revenue increased by $407,000 from $779,000 to $1,186,000 during the years ended December 31, 2005 and 2006, respectively. Interest earned increased by $450,000 from $367,000 during the year ended December 31, 2005 to $817,000 during the year ended December 31, 2006, due to interest on officer and employee notes. Other revenue decreased by $43,000 from $412,000 to $369,000 during the years ended December 31, 2005 and 2006, respectively.

Income tax provisions (benefits). We recorded income tax expense of $2.0 million and $14.4 million for the years ended December 31, 2005 and 2006, respectively. The income tax expense was due to the income reported during the years ended December 31, 2005 and 2006.

We had a net deferred federal and state tax asset at December 31, 2005 in the amount of $4.9 million. This accumulated balance is based on deferred hedge losses and differences in basis of oil and gas properties for tax purposes as compared to book purposes and offset by the effect of a net operating loss. Intangible drilling costs are allowed as deductions by the Internal Revenue Service and are capitalized under the generally accepted accounting principles in the United States of America. At December 31, 2006, we had a net deferred tax liability of $241.7 million. This change is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006, a reduction of deferred hedge losses and the elimination of the net operating loss.

Inception (April 21, 2004) through December 31, 2004, compared to year ended December 31, 2005

Oil and gas revenues. Revenues from oil and gas operations increased by $51.3 million from $3.6 million for the period April 21, 2004 to December 31, 2004 to $54.9 million for the year ended December 31, 2005. This increase was primarily because we did not conduct any substantial operations other than organizational activities from our formation on April 21, 2004 until the acquisition of the Lowe Properties on December 7, 2004. In addition, revenue during the year ended December 31, 2005 increased due to the successful completion of new wells as a result of our drilling activities during 2005. Finally, average oil prices after giving effect to hedging activities increased 28% between 2004 and 2005 from $41.37 per Bbl to $52.79 per Bbl, respectively, and average natural gas prices after giving effect to hedging activities increased 12% between 2004 and 2005 from $6.09 per Mcf to $6.85 per Mcf, respectively. Average natural gas equivalent prices increased 21% from $6.48 per Mcfe in 2004 to $7.85 per Mcfe in 2005.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted by the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in prices to protect economics related to certain capital projects. During 2005, our commodity price hedges decreased oil revenues by $1.2 million ($1.92 per Bbl) and decreased gas revenues by $0.5 million ($0.14 per Mcf). During 2004, there were no settlements of oil or gas hedges as the first hedged period began in January 2005.

Derivatives not designated as hedges. During the period from April 24, 2004 through December 31, 2004, we entered into certain oil and natural gas derivative financial instruments that did not qualify for cash flow hedge accounting treatment under SFAS No. 133. In October 2004, we purchased put contracts for, in the aggregate, 182,500 Bbls of oil and 1,095,000 MMBtu s of natural gas, respectively, for production months in the year ended December 31, 2005. In December 2004, our position in these contracts was exchanged for swap contracts for a like amount of 2005 production. These contracts were originally entered into in anticipation of the acquisition on December 7, 2004 of certain producing oil and natural gas properties from Lowe Partners, LP. The objective of these arrangements was to protect against commodity price fluctuations and achieve a more predictable cash flow. SFAS No. 133 requires that every derivative instrument (including those not designated as cash flow hedges) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 generally requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met and the derivative is designated as a hedge unless exemptions for normal purchases and normal sales as allowed by SFAS No. 133 are applicable.

During the period from April 24, 2004 through December 31, 2004, we recognized gains of approximately $0.7 million as the fair value of these derivative instruments increased because of a decrease in the market price for oil, offset in part by an increase in the market price for natural gas, from the date the contracts were entered into in comparison to market prices at December 31, 2004. During the year ended December 31, 2005, we recorded losses of approximately $5.0 million in these contracts as a result of increases in oil and natural gas prices.

Production expenses. Production costs (including production taxes) increased by $13.9 million from $0.7 million ($1.33 per Mcfe) during the period from April 21, 2004 to December 31, 2004 to $14.6 million ($2.09 per Mcfe) during the year ended December 31, 2005. Lease operating

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expenses and workover costs, the components of production costs over which we have management control, increased by $10.4 million from $0.5 million ($0.91 per Mcfe) during the period from April 21, 2004 to December 31, 2004 to $10.9 million ($1.56 per Mcfe) during the year ended December 31, 2005. The increase in production costs, including lease operating expenses and workover costs, between the period from April 21, 2004 to December 31, 2004 and the year ended December 31, 2005 was primarily because of our less extensive oil and gas operations during the period from April 21, 2004 to December 31, 2004, prior to our acquisition of the Lowe Properties on December 7, 2004. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 10% and 9% of lease operating expenses for 2004 and 2005 respectively.

The secondary component of production costs is production taxes and is directly related to commodity price changes. Our production taxes increased from $0.2 million ($0.42 per Mcfe) during the period from April 21, 2004 to December 31, 2004 to $3.7 million ($0.53 per Mcfe) during the year ended December 31, 2005, primarily due to higher commodity prices and increased production during the year ended December 31, 2005.

Exploration and abandonments / geological and geophysical costs. Exploration and abandonments / geological and geophysical costs increased by $0.8 million from $1.9 million during the period from April 21, 2004 to December 31, 2004 to $2.7 million during the year ended December 31, 2005. The exploration and abandonments / geological and geophysical costs during the period from April 21, 2004 to December 31, 2004 consisted of $1.3 million of exploratory dry hole costs and $0.6 million of geological and geophysical costs. The geological and geophysical costs for the period from April 21, 2004 to December 31, 2004 included a non-cash charge of $0.4 million related to an abandoned prospect in the Gulf Coast region. The exploration and abandonments / geological and geophysical costs during the year ended December 31, 2005 consisted of $1.4 million of exploratory dry hole costs and $1.3 million of geological and geophysical costs. The exploratory dry hole costs during the year ended December 31, 2005 were attributable to two wells drilled in the Permian Basin region that we operated and one well in the Gulf Coast region that we did not operate.

Depreciation and depletion expense. Our total depreciation and depletion expense increased by $10.5 million from $1.0 million ($1.71 per Mcfe) during the period from April 21, 2004 to December 31, 2004 to $11.5 million ($1.64 per Mcfe) during year ended December 31, 2005. The increase in the total depreciation and depletion expense was primarily because of the impact of the acquisition of the Lowe Properties on the full year ended December 31, 2005. Our depreciation and depletion expense per Mcfe decreased from during the period from April 21, 2004 to December 31, 2004 to the year ended December 31, 2005 because of additional reserves added to the depletable properties base during 2005 resulting from the Company s successful drilling operations.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we reviewed 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 2005, we recognized a non-cash charge against earnings of $2.3 million related to our proved oil and gas properties. At December 31, 2004, we did not recognize a charge against earnings related to our proved oil and gas properties.

General and administrative expenses. General and administrative expenses increased by $7.1 million from $4.2 million ($7.54 per Mcfe) during the period from April 21, 2004 to December 31, 2004 to $11.3 million ($1.62 per Mcfe) during the year ended December 31, 2005, respectively.

Excluding non-cash stock-based compensation of $1.1 million in 2004 and $3.3 million in 2005, our general and administrative expenses increased by $4.9 million from $3.1 million ($5.52 per Mcfe) during the period from April 21, 2004 to December 31, 2004 to $8.1 million ($1.15 per Mcfe) during the year ended December 31, 2005. The increase in general and administrative expense during the year ended December 31, 2005 was primarily because of increased business activity in 2005 as well as the hiring of additional staff in 2005. From time to time, we also earn revenue in our capacity as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $38,000 and $591,000 during the period from April 21, 2004 to December 31, 2004 and during the year ended December 31, 2005, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Interest expense. Interest expense increased by $2.8 million from $0.3 million during the period from April 21, 2004 to December 31, 2004 to $3.1 million during the year ended December 31, 2005. The increase in interest expense during the year ended December 31, 2005 was primarily due to increased borrowings under our former revolving credit facility that we incurred to fund a portion of the cash consideration for the Lowe Properties. Prior to October 14, 2004, the date on which we were required to make a cash escrow deposit for the acquisition of the Lowe Properties, we had not borrowed any funds under the former revolving credit facility.

Other, net. Interest and other revenue increased by $611,000 from $168,000 during the period from April 21, 2004 to December 31, 2004 to $779,000 during the year ended December 31, 2005. Interest earned increased by $256,000 from $111,000 during the period from April 21, 2004 to December 31, 2004 to $367,000 during the year ended December 31, 2005 due to interest on officer and employee notes. Other revenue increased by $355,000 from $57,000 during the period from April 21, 2004 to December 31, 2004 to $412,000 during the year ended December 31, 2005.

Income tax provisions (benefits). We recorded an income tax benefit of $0.9 million during the period from April 21, 2004 to December 31, 2004 and an income tax expense of $2.0 million during the year ended December 31, 2005. The income tax benefit during the period from April 21, 2004 to December 31, 2004 was due to the loss we reported during that period while the income tax expense during the year ended December 31, 2005 was due to the income we reported during that period.

We recognized a net deferred federal and state tax asset during the period from April 21, 2004 to December 31, 2004 in the amount of $0.9 million at December 31, 2004. This accumulated balance is based on differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes offset by the effects of a net operating loss and the tax effects of deferred hedge gains. The deferred tax asset increased by $4.0 million from December 31, 2004 to December 31, 2005, primarily due to the tax effect of deferred hedge losses offset by an increase in intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principles in the United States of America.

Liquidity and capital resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facilities. We believe that funds from operating cash flows and our bank credit facilities should be sufficient to meet both our short-term working capital requirements and our 2007 exploration and development budget.

Cash flow from operating activities

Our net cash provided by operating activities was $11.6 million and $31.0 million for the three months ended March 31, 2006 and 2007, respectively. The increase in operating cash flows during the three months ended March 31, 2007 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.

Our net cash provided by operating activities was $25.1 million and $112.2 million for the years ended December 31, 2005 and 2006, respectively. The increase in operating cash flows in 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 three months ended March 31, 2006 and 2007, we invested $446.5 million and $36.6 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 three months ended March 31, 2006, primarily due to the $400 million cash portion of the consideration we paid to the Chase Group in the combination transaction. We determined to reduce our drilling activities and curtail capital expenditures during the three months ended March 31, 2007 until we were able to complete our second lien term loan facility in March 2007 in order to preserve liquidity. See Items impacting comparability of our financial results Curtailment of drilling above.

During the years ended December 31, 2005 and 2006, we invested $55.6 million and $595.6 million, respectively, in our capital program, inclusive of dry hole costs. Cash flows used in investing activities increased during the year ended December 31, 2006, primarily due to the $409 million cash portion of the consideration we paid to the Chase Group in the combination transaction and drilling activities in 2006.

Cash flow from financing activities

Net cash provided by financing activities was $426.2 million and $7.0 million for the three months ended March 31, 2006 and 2007, respectively. Cash provided by financing activities in the three months ended March 31, 2006 was primarily due to borrowings under our revolving credit facility to fund the approximate $400 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.

Net cash provided by financing activities was $45.4 million and $476.6 million for the years ended December 31, 2005 and 2006, respectively. In 2005, cash provided by financing activities was primarily attributable to net proceeds from the issuance of debt and equity in our company, partially offset by payment of dividends on preferred stock. The increase during 2006 was primarily due to borrowings under our revolving credit agreement to fund the approximate $409 million cash portion of the consideration paid to the Chase Group and associated persons pursuant to the combination transaction and proceeds from private issuances of equity in our company.

Bank credit facilities

We have two separate bank credit facilities. The first bank credit facility is our Credit Agreement, dated as of February 24, 2006, with JPMorgan Securities Inc. as the administrative agent for a group of lenders that provides a revolving line of credit having a total commitment of $475 million, which we refer to as the revolving credit facility. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of the total commitment of $475 million or the borrowing base established by the lenders. As of December 31, 2006, the borrowing base under our revolving credit facility was $475 million, but was reduced to $375 million on March 27, 2007 in connection with the completion of our second lien term loan facility described below. As of March 31, 2007, the principal amount outstanding under our revolving credit facility was $306.0 million. In February 2006, we incurred borrowings of approximately $421.0 million under our revolving credit facility in connection with the combination transaction to pay the cash purchase price of $400.0 million to the Chase Group, $15.9 million to repay the balance on the prior revolving credit facility of Concho Equity Holdings Corp. and approximately $5.1 million for bank fees and legal costs associated with our revolving credit facility. We also incurred borrowings of approximately $8.9 million in May 2006 in connection with the purchase of additional working interests in the Chase Group Properties pursuant to the combination transaction from persons associated with the Chase Group. The remaining borrowings under our revolving credit facility during 2006 were used for working capital and to fund a portion of our exploration and development drilling program.

The second bank credit facility is our Second Lien Credit Agreement, dated as of March 27, 2007, with Bank of America, N.A., as the administrative agent for the other lenders thereunder, that provides a five year term loan in the amount of $200.0 million, which we refer to as the second lien term loan facility. Upon execution of the second lien term loan facility, we funded the full amount under that facility and received proceeds of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes. We expect to use not less than one-half of the net proceeds we receive from this offering to repay a portion of our outstanding indebtedness under the second lien term loan facility and to use any remaining net proceeds to repay a portion of our outstanding indebtedness under our second lien term loan facility or our revolving credit facility or a combination thereof as described in Use of proceeds.

Revolving credit facility. The revolving credit facility allows us to borrow, repay and reborrow amounts available under the revolving credit facility. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base under our revolving credit facility is re-determined at least semi-annually. The revolving credit facility matures on February 24, 2010, and borrowings under our revolving credit facility bear interest, payable quarterly, at our option, at (1) a rate (as defined and further described in our revolving credit facility) per annum equal to a Eurodollar Rate (which is substantially the same as the London Interbank Offered Rate) for one, two, three or six months as offered by the lead bank under our revolving credit facility, plus an applicable margin ranging from 100 to 225 basis points, or (2) such bank s Prime Rate, plus an applicable margin ranging from 0 to

125 basis points, dependent in each case upon the percentage of our available borrowing base then utilized. Our revolving credit facility bore interest at 6.87% per annum as of March 31, 2007. We pay quarterly commitment fees under our revolving credit facility on the unused portion of the available borrowing base ranging from 25 to 50 basis points, dependent upon the percentage of our available borrowing base then utilized.

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

Second lien term loan facility. The second lien term loan facility provides a $200 million term loan, which bears interest, at our option, at (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 375 basis points or (2) the prime rate, plus an applicable margin of 225 basis points. Upon the completion of this offering, the interest rate under any of the second lien term loan facility that remains outstanding after the application of the net proceeds from this offering as described in Use of proceeds increases, at our option, to (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 425 basis points or (2) the prime rate, plus an applicable margin of 275 basis points. We have the option to select different interest periods, subject to availability, and interest is payable at the end of the interest period we select, though such interest payments must be made at least on a quarterly basis. We are required to repay $500,000 of the second lien term loan facility on the last day of each calendar quarter, commencing June 30, 2007, until the remaining balance of the loan matures on March 27, 2012. Our second lien term loan facility currently bears interest at 9.10% per annum. We have the right to prepay the outstanding balance under the second lien term loan facility at any time, provided, however, that we will incur a 2% prepayment penalty on any principal amount prepaid from March 27, 2008 until March 26, 2009 and a 1% prepayment penalty on any principal amount prepaid from March 27, 2009 until March 26, 2010.

Borrowings under the second lien term loan facility are secured by a second lien on the same assets as are securing our revolving credit facility, which liens are subordinated to liens securing our revolving credit agreement. The second lien term loan facility also contains various restrictive financial covenants and compliance requirements that are similar to those contained in the revolving credit agreement, including the maintenance of certain financial ratios.

Future capital expenditures and commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and gas properties that provide opportunities for the addition of reserves and production

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through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise or that otherwise have geologic characteristics that are similar to our existing properties.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $154 million for exploration and development expenditures in 2007 as follows (in millions):

		Amount
Drilling and recompletion opportunities in our core operating area	$	119.4
Projects in our emerging plays		15.7
Projects operated by third parties		14.2
Acquisition of leasehold acreage and other property interests		4.7
	$	154.0

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2007 exploration and development budget. 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.

Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments. We generally attempt to qualify such derivative instruments as cash flow hedges for accounting purposes.

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

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The tables below provide the volumes and related data associated with our oil and natural gas hedging as of March 31, 2007:

Oil and Natural Gas Price Collars

Period of time	Barrels of oil	NYMEX oil prices Floor	NYMEX oil prices Cap	MMBtus of natural gas	El Paso Natural Gas Permian Basin natural gas prices Floor	El Paso Natural Gas Permian Basin natural gas prices Cap	Fair market value
							(in thousands)
April 1, 2007 thru December 31, 2007	178,750	$ 37.95	$ 41.75		$	$	$ (4,724)
April 1, 2007 thru December 31, 2007		$	$	962,500	$ 5.00	$ 6.02	$ (1,345)
April 1, 2007 thru December 31, 2007		$	$	3,437,500	$ 6.25	$ 10.80	$ 639
January 1, 2008 thru December 31, 2008		$	$	4,941,000	$ 6.50	$ 9.35	$ (1,936)
Total net fair market value asset (liability)							$ (7,366)

Oil and Natural Gas Price Swaps

Period of time	Barrels of oil	NYMEX oil swap prices	MMBtus of natural gas	El Paso Natural Gas Permian Basin natural gas swap price	Fair market value
					(in thousands)
April 1, 2007 thru December 31, 2007			577,500	$ 7.40	$ (6)

April 1, 2007 thru December 31, 2007	632,500	$	67.85	$	$	(576)
January 1, 2008 thru December 31, 2008	951,600	$	67.50	$	$	(2,197)
Total fair market value asset (liability)					$	(2,779)

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Obligations and commitments

We had the following contractual obligations and commitments as of December 31, 2006:

				Payments due by period	
(In thousands)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Long-term debt[1]	$ 495,500	$ 400	$ 800	$ 494,300	$
Operating lease obligation[2]	3,125	438	888	926	873
Daywork drilling contracts[3]	14,445	14,445			
Chase Group asset purchase obligation[4]	906	906			
Oil and gas lease extension payment[5]	2,093	2,093			
Employment agreements with executive officers[6]	4,103	1,700	2,403		
Asset retirement obligations[7]	8,700	1,958	194	169	6,379
Total contractual cash obligations	$ 528,872	$ 21,940	$ 4,285	$ 495,395	$ 7,252

(1) Our long-term debt increased by $5.2 million on March 27, 2007, excluding accrued interest, as a result of funding our second lien term loan facility.

(2) Operating lease obligation is for office space.

(3) Consists of daywork drilling contracts related to five drilling rigs contracted for a portion of 2007. See Note K to our consolidated financial statements.

(4) Represents the value of certain oil and gas interests contracted to be acquired from Chase Group members. We are obligated to offer to deliver aggregate consideration of $906,000, in cash or common stock or any combination of the foregoing to these individuals. See Note K to our consolidated financial statements.

(5) Represents an obligation for an additional payment to be made in 2007 in connection with our prior leasing of 13,952 net acres in Culberson County, Texas.

(6) 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 in the discretion of the board of directors.

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

Off-balance sheet arrangements

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

Critical accounting policies and practices

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

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

Successful efforts method of accounting

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

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

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

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

Oil and natural gas reserves and standardized measure of future cash flows

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

Asset retirement obligations

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

Impairment of assets

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

Recent accounting pronouncements

In December 2004, the FASB issued SFAS No. 123 (Revised 2004), Share-Based Payment . SFAS No. 123R addresses the accounting for transactions in which an enterprise exchanges its valuable equity instruments for employee services. It also addresses transactions in which an enterprise incurs liabilities that are based on the fair value of the enterprise s equity instruments or that may be settled by the issuance of those equity instruments in exchange for employee

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services. The cost of employee services received in exchange for equity instruments, including employee stock options, would be measured based on the grant-date fair value of those instruments. That cost would be recognized as compensation expense over the requisite service period (often the vesting period). Generally, no compensation cost would be recognized for equity instruments that do not vest. We adopted SFAS No. 123R in 2005 and applied the modified retrospective application method to all prior periods. We previously utilized the method of accounting for stock based compensation prescribed by APB 25 and included disclosures in the footnotes to the consolidated financial statements which illustrated the results we would have recorded had we utilized the fair value method prescribed by SFAS No. 123 Accounting for Stock-Based Compensation in our primary financial statements.

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

We adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) on January 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement 109, Accounting for Income Taxes , 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 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

Based on our evaluation, we have concluded that there are no significant uncertain tax positions requiring recognition in our financial statements. Our evaluation was performed for the tax periods ended December 31, 2004, 2005 and 2006, which are the tax periods which remain subject to examination by major tax jurisdictions.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement . This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We will adopt SFAS No. 157 effective January 1, 2008. We are currently evaluating the impact of SFAS No. 157.

In September 2006, the SEC issued Staff Accounting Bulletin (SAB) 108, Financial Statements Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB 108 requires quantification of the impact of all prior year misstatements from both an income statement and a balance sheet perspective to determine if the misstatements are material. SAB 108 is effective for financial statements issued for fiscal years ending after November 15, 2006. We adopted SAB 108 effective at the inception of Concho Equity Holdings Corp.

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Inflation

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

Quantitative and qualitative disclosures 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 including the use of derivative instruments.

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 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 partially reduce price risk caused by these market fluctuations, we have hedged approximately 75% of our forecasted oil and natural gas production through December 31, 2008, attributable to our proved developed producing reserves as of December 31, 2005, through the utilization of derivatives, including zero-cost collars and fixed price contracts. See Liquidity and capital resources Hedging.

Interest rate risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our bank credit facilities, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. We had total indebtedness of $306.0 million outstanding under our revolving credit facility at March 31, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $3.1 million and a corresponding decrease in net income before income tax. On March 27, 2007, we entered into a $200.0 million second lien term loan facility, from which we received $199.0 million in proceeds, with $39.8 million of such amount used to retire our prior second lien term loan facility, $154.0 million of such amount used to reduce the amount outstanding under our revolving credit facility and the remaining $5.2 million of such amount used to pay loan fees, accrued interest and for general corporate purposes. The impact of a 1% increase in interest rates on this amount of debt under our second lien term loan facility would result in increased interest expense of approximately $2.0 million and a corresponding decrease in net income before income tax.

Results of operations of the Chase Group Properties

The following table presents selected financial and operating information of the Chase Group Properties for the years ended December 31, 2004 and 2005:

(in thousands, except price data)	Years ended December 31, 2004	2005
Oil sales	$ 66,529	$ 73,132
Natural gas sales	41,247	46,546
Total operating revenues	107,776	119,678
Oil and gas production	11,762	12,979
Oil and gas production taxes	9,202	10,298
Depreciation, depletion and amortization	20,196	18,646
Impairments of proved properties	3,233	194
Exploration and abandonments	179	
Accretion of discount on asset retirement obligations	263	446
General and administrative	1,387	1,702
Loss on derivatives not designated as hedges	7,936	1,062
Total operating costs and expenses	54,158	45,327
Revenues in excess of expenses	$ 53,618	$ 74,351
Production volumes (unaudited):		
Oil (MBbl)	1,751	1,429
Natural gas (MMcf)	7,636	6,636
Natural gas equivalents (Mcfe)	18,142	15,210
Average prices (unaudited):		
Oil ($/Bbl)	$ 37.99	$ 51.17
Natural gas ($/Mcf)	5.40	7.01
Natural gas equivalents ($/Mcfe)	5.94	7.87

Year ended December 31, 2004, compared to year ended December 31, 2005

Oil and gas revenues. Revenue from oil and gas operations increased by $11.9 million (11%) from $107.8 million for the year ended December 31, 2004 to $119.7 million for the year ended December 31, 2005. This increase was primarily because of increased commodity prices which more than offset the declines in production. Total production decreased 2,932 MMcfe (16%) from 18,142 MMcfe for the year ended December 31, 2004 to 15,210 MMcfe for the year ended December 31, 2005. Production decreased because capital funds expended for property acquisition and development was not sufficient to overcome the natural decline of the existing wells. Average realized oil prices increased 35% from $37.99 per Bbl in 2004 to $51.17 per Bbl in 2005, average realized natural gas prices increased 30% from $5.40 per Mcf in 2004 to $7.01 per Mcf in 2005 and total realized production equivalent prices increased 32% from $5.94 per Mcfe in 2004 to $7.87 per Mcfe in 2005.

Oil and gas production costs. Total operating costs increased $2.3 million (11%) from $21.0 million ($1.16 per Mcfe) to $23.3 million ($1.53 per Mcfe) for the years ended December 31, 2004 and 2005, respectively. The increase in operating costs was due to general increases in oil and gas service and equipment rates. Lease operating expenses and workover costs comprised approximately 56% of total operating costs during both 2004 and 2005. These costs per unit of production increased 31% from $0.65 per Mcfe in 2004 to $0.85 per Mcfe in 2005. Per unit costs increased because of increases in oil and gas service and equipment rates along with lower production volumes. Included in operating costs are costs of salaries and benefits of pumpers and field level supervisors of the Chase Group and the Chase Group s share of general liability insurance that do not necessarily decrease when production volumes decrease.

Oil and gas production taxes. Production taxes comprised approximately 44% of total operating costs for 2004 and 2005. Production taxes per unit of production increased 33% from $0.51 per Mcfe in 2004 to $0.68 per Mcfe in 2005. This increase was directly related to an increase in commodity prices. In general, production taxes rates are based on the value of production rather than production volumes.

Depletion, depreciation and amortization expense. Total depletion, depreciation and amortization expense decreased $1.6 million (8%) from $20.2 million ($1.11 per Mcfe) to $18.6 million ($1.23 per Mcfe) for the years ended December 31, 2004 and 2005, respectively. The decrease in total expense was primarily due to lower production volumes.

Impairment of oil and gas properties. In accordance with SFAS 144, the long-lived assets of the Chase Group Properties to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting are reviewed. As a result of this review of the recoverability of the carrying value of its assets during 2004, the Chase Group Properties recognized non-cash charges against earnings of $3.3 million related to its proved oil and gas properties. During 2005, the Chase Group Properties recognized non-cash charges against earnings of $0.2 million related to its proved oil and gas properties.

General and administrative expenses. General and administrative expenses increased $0.3 million (21%) from $1.4 million ($0.08 per Mcfe) to $1.7 million ($0.11 per Mcfe) for the years ended December 31, 2004 and 2005, respectively. The increase in general and administrative expense during 2005 was primarily because of increases in compensation expenses.

Loss on derivatives not designated as hedges. Gains and losses on derivative transactions are a result of fluctuations in oil and natural gas prices and, consequently, the change in fair values of derivatives as included in our earnings for each accounting period. Losses in 2004 exceeded those in 2005 because the derivative transactions were entered into in the second quarter of 2004, resulting in 2004 mark-to-market adjustments being larger due to larger remaining contractual volumes than in 2005. Also, no derivative transactions were outstanding for the period of June 2005 through December 2005.

Business and properties

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

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

Our operations are primarily concentrated in the Permian Basin, the largest onshore oil and gas basin in the United States. As of December 31, 2006, 99% of our total estimated net proved reserves were located in the Permian Basin and consisted of approximately 57% crude oil and 43% natural gas. This basin is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. The primary producing formation in the Permian Basin under our core properties in Southeast New Mexico is the Paddock interval of the Yeso formation, which is located at depths ranging from 3,800 feet to 5,800 feet. We have also discovered reserves and are producing oil and natural gas from the Blinebry interval of the Yeso formation, the top of which is located approximately 400 feet below the base of the Paddock interval. In addition, we have assembled a multi-year inventory of development drilling and exploitation projects, including further projects to evaluate the aerial extent of the Blinebry interval, that we believe will allow us to grow proved reserves and production. We have also acquired significant acreage positions in the Permian Basin of Southeast New Mexico, the Central Basin Platform, the Delaware Basin and the Val Verde Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas covering unconventional emerging resource plays, where we intend to apply horizontal drilling, advanced fracture stimulation and/or enhanced recovery technologies.

Following the formation of our company, we drilled 140 gross (86.4 net) wells in 2006, 89% of which were completed as producers, 7% of which were dry holes and 4% of which are awaiting completion. In addition, following the formation of our company, we recompleted 103 gross (77.1 net) wells in 2006, 98% of which were productive. As a result, we have increased our total estimated net proved reserves by approximately 51 Bcfe from 416 Bcfe as of December 31, 2005, on a pro forma basis, to 467 Bcfe as of December 31, 2006, while producing approximately 26 Bcfe of oil and natural gas on a pro forma basis during the year ended December 31, 2006. In addition, following the formation of our company, we increased our average net daily production from 62 MMcfe during March 2006 to 80 MMcfe during March 2007.

The following table provides a summary of selected operating information of our conventional properties in the Permian Basin, which is our core operating area, and in our unconventional emerging resource plays. 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

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proceeds from each of these properties. We set forth our definition of PV-10 (a non-GAAP financial measure) and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows under Prospectus summary Non-GAAP financial measures and reconciliations.

	As of December 31, 2006					As of March 31, 2006		Year ended December 31, 2006	Three months ended March 31, 2007
Areas	**Total proved reserves (Bcfe)**	**PV-10 ($ in millions)**	**Pro forma reserve/ production index[(1)] (years)**	**Identified drilling locations[(2)]**	**Identified recompletion projects[(2)]**	**Total gross acreage**	**Total net acreage**	**Pro forma average daily production (MMcfe/d)**	**Average net daily production (MMcfe/d)**
Permian Basin									
Southeast New Mexico	387.5	$ 782.6	18.7	1,505	489	170,275	76,583	56.8	63.8
West Texas	70.2	154.5	15.5	148	49	91,687	34,765	12.4	13.4
Emerging Plays and Other[(3)]	9.1	16.9	19.2	23	2	234,098	125,245	1.3	2.8
Total	466.8	$ 954.0	18.1	1,676	540	496,060	236,593	70.5	80.0

(1) The Pro forma reserve/production index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing pro forma production during the year ended December 31, 2006, into the proved reserve quantity as of December 31, 2006. Pro forma production during the year ended December 31, 2006 was 25,735.0 MMcfe, consisting of 20,734.0 MMcfe in the Southeast New Mexico part of the Permian Basin, 4,526.5 MMcfe in the West Texas part of the Permian Basin and 474.5 MMcfe in Emerging Plays and Other. Pro forma production information assumes the combination transaction had taken place on January 1, 2006.

(2) The identified drilling locations and identified recompletion projects listed in the table above included 817 drilling locations and recompletion projects for which proved reserves had been included in our reserve reports as of December 31, 2006.

(3) Information with respect to Other includes conventional oil and gas operations on properties that are not located in the Permian Basin. As of December 31, 2006, 3.1 Bcfe of the proved reserves and $5.4 million of the PV-10 as well as one of the identified drilling locations and two identified recompletion projects were related to oil and natural gas properties categorized as Other and not as Emerging Plays. In addition, as of March 31, 2007, 4,948 gross (797 net) acres reflected above were categorized as Other, and 1.1 MMcfe/d of the average daily production during the three months ended March 31, 2007 reflected above were categorized as Other.

An unconventional emerging resource play generally consists of a large area that, based on its geological and geophysical characteristics, indicates the possible existence of a continuous accumulation of hydrocarbons. These plays are typically associated with tight, fractured rocks, such as fractured shales, fractured carbonates, coal seams and tight sands, which may serve as the source of the hydrocarbons and as the productive reservoir. In our unconventional emerging resource plays, we target areas where we can acquire large undeveloped acreage positions and apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies to achieve economic, repeatable production results. As of March 31, 2007, we held interests in 229,150 gross (124,448 net) acres in six unconventional emerging resource plays. Our current positions include acreage in:

- the Northwest Shelf area in Southeast New Mexico, where we have tested one re-entry well and drilled seven exploratory wells targeting the Wolfcamp Carbonate;
- the Central Basin Platform of West Texas, where we plan to target the Woodford Shale;
- the Delaware Basin of West Texas, where we have drilled four exploratory wells targeting the Bone Spring, Atoka, Barnett and Woodford Shales;

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the Val Verde Basin of West Texas, where we plan to drill our first test well in 2007, which will target the Ellenburger Dolomite and the Canyon Sands;

the North Dakota portion of the Williston Basin, where we have drilled two exploratory wells targeting the Bakken Shale; and

the eastern Arkoma Basin in Arkansas, where we plan to drill our first test well prior to March 31, 2008, which will target the Fayetteville Shale.

Our exploration and development budget for our oil and gas properties for the year ending December 31, 2007 is approximately $154 million. We plan to spend approximately 87% of our capital budget on exploration and development activities associated with our conventional properties in the Permian Basin, 3% for leasehold acquisitions and 10% for exploration activities in our unconventional emerging resource plays. If we achieve successful results from exploratory drilling in our unconventional emerging resource plays, we may allocate a greater portion of our planned 2007 capital expenditure budget to those plays. As of March 31, 2007, we had incurred $27 million of costs associated with our 2007 exploration and development budget.

Our business strategy

Our goal is to enhance stockholder value through profitably increasing reserves, production and cash flow by executing our strategy as described below:

Exploit our multi-year project inventory. We believe our multi-year drilling and exploitation inventory will allow us to grow our proved reserves and production for the next several years. As of December 31, 2006, we had identified 2,216 drilling locations and recompletion projects on our existing properties, including step-out drilling, infill drilling (including well deepening opportunities), workovers and recompletions.

Enhance production from our existing properties through development of additional producing horizons and enhanced recovery methods. We believe there are additional productive horizons underlying certain of our existing producing horizons in Southeast New Mexico that have not been fully developed. During 2006, we accelerated an evaluation, which had begun in late 2005, of the Blinebry interval, which lies below the primary producing interval under our core properties in Southeast New Mexico. During 2006, we drilled 52 wells in the Blinebry interval, all of which have since been completed as producers. At December 31, 2006, the wells in the Blinebry interval which had been drilled and completed and were producing only from the Blinebry interval were producing an average of 80 Bbl and 176 Mcf per well per day. During the three months ended March 31, 2007, we drilled an additional five wells in the Blinebry interval, four of which have since been completed as producers and one of which was a dry hole. We intend to drill an additional 68 wells in 2007 to further evaluate the aerial extent of the Blinebry interval. In addition, we are evaluating the feasibility of enhanced recovery operations on a significant portion of our Southeast New Mexico properties.

Pursue the acquisition, exploration and development of unconventional emerging oil and natural gas resource plays. We have assembled an exploration team to target unconventional emerging resource plays where we can acquire large undeveloped acreage positions and apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies to achieve economic, repeatable production results. Members of our technical staff, consisting of six petroleum engineers, seven geoscientists and eight landmen, have, on average, more than 23 years experience in the industry. As of March 31, 2007, we had accumulated 229,150 gross (124,448 net) acres in six unconventional emerging resource plays, and our

technical team is focused on exploring, developing and exploiting these resource plays as well as evaluating and acquiring acreage in similar plays in North America.

Make opportunistic acquisitions that meet our strategic and financial objectives. We seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. We have an experienced team of management, engineering and geoscience professionals to identify and evaluate acquisition opportunities. We also seek to acquire other oil and gas properties that provide opportunities for the addition of reserves, production and value through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise or that otherwise have geologic characteristics that are similar to our existing properties.

Our strengths

We have a number of strengths that we believe will help us successfully execute our strategy:

Experienced and incentivized management team. Our executive officers average over 19 years of experience in the oil and gas industry, having led both public and private oil and natural gas exploration and production companies. These companies have had substantially all of their operations in our core area of the Permian Basin and were headquartered in Midland, Texas, which is located in the heart of the Permian Basin. After giving effect to this offering, our executive officers will beneficially own an aggregate of % of our outstanding common stock, which will align their objectives with those of our stockholders.

History of growth and capital efficiency. During the year ended December 31, 2006, we increased our total estimated net proved reserves by approximately 51 Bcfe from 416 Bcfe as of December 31, 2005, on a pro forma basis, to 467 Bcfe as of December 31, 2006, and produced approximately 26 Bcfe of oil and natural gas on a pro forma basis. In addition, following the formation of our company, we increased our average net daily production from 62 MMcfe during March 2006 to 80 MMcfe during March 2007. The increase in reserves and production during the year ended December 31, 2006 was primarily attributable to our successful drilling program in the Permian Basin. Despite increasing costs of oilfield services and equipment in our areas of operation, we added 101 Bcfe of proved reserves in 2006 through new discoveries and extensions, excluding revisions of previous estimates at a total cost of $193.3 million.

Large inventory of drilling and recompletion opportunities. Following the formation of our company, we drilled 140 gross (86.4 net) wells in 2006, of which 125 gross (81.4 net) wells were completed as producers, and 10 gross (3.2 net) wells were dry holes. In 2007, we have drilled 9 gross (5.7 net) wells through March 31, 2007, of which 5 gross (3 net) wells were completed as producers, 1 gross (1 net) well was a dry hole and 3 gross (1.7 net) wells are awaiting completion. In addition, following the formation of our company, we recompleted 103 gross (77.1 net) wells in 2006, 98% of which were productive. In 2007, we have recompleted 28 gross (23.8 net) wells through March 31, 2007, 96% of which were productive. As of December 31, 2006, we had identified 1,676 undrilled well locations on our acreage, with proved undeveloped reserves attributed to 595 of such locations, and 540 recompletion opportunities, with proved reserves attributed to 222 of such opportunities. We plan to drill an additional 133 wells and recomplete an additional 67 wells during 2007.

Geographically concentrated operations. Our current operations are focused in the Permian Basin of Southeast New Mexico and West Texas, where 99% of our proved reserves are located. Our geographic concentration allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, in addition to further leveraging our base of technical expertise in this region.

Significant operational control. As of December 31, 2006, we operated 916 gross (824 net) wells on properties which comprised 89% of our PV-10. As of March 31, 2007, we operated 920 gross (828 net) wells. Additionally, as of December 31, 2006, approximately 72% of our identified drilling locations and recompletion projects were associated with properties we operate. Our high proportion of operated properties enables us to exercise a significant level of control over the amount and timing of expenses, capital allocation and other aspects of exploration and development.

Combination transaction

On February 24, 2006, we entered into a combination agreement in which we agreed to purchase certain oil and gas properties owned by Chase Oil Corporation, Caza Energy LLC and certain other individual 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. As a result of the initial closing of the combination transaction agreement, the members of the Chase Group that sold their working interests to us at the initial closing of the combination transaction received 69,366,627 shares of our common stock and approximately $400 million in cash, and the former shareholders of Concho Equity Holdings Corp. that were a party to the combination agreement received 47,535,346 shares of our common stock. In addition, certain options held by our employees to purchase preferred and common stock of Concho Equity Holdings Corp. were converted into options to purchase 4,698,331 shares of our common stock. The oil and gas properties contributed to us by the Chase Group (which we refer to as the Chase Group Properties) represent approximately 76% of our PV-10 as of December 31, 2006. The executive officers of Concho Equity Holdings Corp. became the executive officers of our company in connection with the initial closing of the combination transaction. We have accounted for the combination transaction as a reorganization of our company, such that Concho Equity Holdings Corp. is now our wholly owned subsidiary, and a simultaneous acquisition by our company of the assets contributed by the Chase Group.

We agreed in the combination agreement to offer to acquire additional interests in the Chase Group Properties from persons associated with the Chase Group. In May 2006, we acquired certain of such interests from ten of such persons in exchange for an aggregate consideration of 222,645 shares of our common stock and $8.9 million in cash. In April 2007, we offered to acquire the remainder of such interests from an additional nine persons in exchange for, at the respective seller s option, shares of our common stock or cash, or any combination thereof, aggregating a total purchase offer of $906,000. Terms concerning the exchange of such interests for shares of our common stock were the same as the terms in the combination agreement.

In addition, because certain employee stockholders of Concho Equity Holdings Corp. were not confirmed to have been accredited investors at the time of the combination transaction, their 254,621 units, consisting of one preferred and one common share of Concho Equity Holdings Corp., could not be immediately exchanged for our common shares. On April 16, 2007, these remaining shares of Concho Equity Holdings Corp. were exchanged for 636,555 shares of our common stock. As a result, Concho Equity Holdings Corp. is now our wholly owned subsidiary.

Prior to the completion of this offering, the field operations of the oil and gas properties we acquired from the Chase Group were conducted on our behalf and at our direction by employees of Mack Energy Corporation, an affiliate of Chase Oil. Upon the completion of this offering, our employees, along with third party contractors, if necessary, will assume those operations. For more information about our transactions with certain affiliates of Chase Oil, please see Certain relationships and related party transactions.

Concho Equity Holdings Corp. was formed in April 2004 by our existing senior management team and private equity investors, and it commenced oil and gas operations in December 2004 upon its acquisition of the Lowe Properties for approximately $117 million. As of January 1, 2006, Concho Equity Holdings Corp. had 107.5 Bcfe in proved oil and natural gas reserves that were primarily located in the Permian Basin of Southeast New Mexico and West Texas. As of that same date, Concho Equity Holdings Corp. also held exploration leasehold acreage in emerging resource plays in the Wolfcamp Carbonate in Southeast New Mexico, the Delaware Basin Shale plays in West Texas, the Bakken Shale in North Dakota and the Fayetteville Shale in Arkansas. As a result of the combination transaction, we acquired all of the oil and gas properties and related operations of Concho Equity Holdings Corp., and now employ its personnel.

Chase Oil is a private company formed by Mack C. Chase in 1992 to engage in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Permian Basin region of Southeast New Mexico. The oil and gas interests contributed by the Chase Group in the combination transaction represented a portion of the total assets held by the Chase Group. As of January 1, 2006, the net interests in the properties contributed by the Chase Group in the combination transaction consisted of 305.5 Bcfe in net proved oil and natural gas reserves located in the Permian Basin region of Southeast New Mexico.

After the closing of the combination transaction, the former holders of Concho Equity Holdings Corp. owned approximately 41% of our outstanding common stock, the Chase Group owned the remaining 59%, and the executive officers of Concho Equity Holdings Corp. became the executive officers of our company. The oil and gas property interests contributed by the Chase Group represented approximately 76% of our pro forma PV-10 as of December 31, 2006. These oil and gas properties are primarily located in Lea and Eddy Counties in New Mexico.

Productive wells

The following table presents our total gross and net productive wells by region and by oil or gas completion as of March 31, 2007:

	Oil wells		Natural gas wells		Total wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Permian Basin:						
Southeast New Mexico	1,223	732.2	178	51.6	1,401	783.8
West Texas	416	132.0	65	10.9	481	142.9
Emerging Plays and Other	5	1.1	40	5.6	45	6.7
Total	1,644	865.3	283	68.1	1,927	933.4

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Developed and undeveloped acreage

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

	Developed acres		Undeveloped acres		Total acres	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin:						
Southeast New Mexico	108,968	54,208	61,307	22,375	170,275	76,583
West Texas	76,745	25,545	14,942	9,220	91,687	34,765
Emerging Plays and Other[(1)]	17,898	7,556	216,200	117,689	234,098	125,245
Total	203,611	87,309	292,449	149,284	496,060	236,593

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

	Total acres	
	Gross	Net
Southeast New Mexico	53,618	21,235
Central Basin Platform	9,548	9,548
Western Delaware Basin	68,814	22,794
Val Verde Basin	39,999	39,609
Williston Basin of North Dakota	40,149	16,810
Arkoma Basin of Arkansas	17,022	14,452
Total Emerging Plays	229,150	124,448
Other	4,948	797
Total Emerging Plays and Other	234,098	125,245

The following table sets forth the amount of our gross and net undeveloped acreage as of December 31, 2006 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2007		2008		2009	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Permian Basin:						
Southeast New Mexico	5,805	2,876	23,696	7,490	8,601	3,423
West Texas	3,991	2,072	14,155	3,200	2,726	1,975
Emerging Plays and Other[1]	2,621	2,671	11,358	2,766	72,260	43,316
Total	12,417	7,619	49,209	13,456	83,587	48,714

(1) We have the option to extend the expiration terms by two additional years (beginning October 2007 through May 2008) on approximately 6,400 gross (4,800 net) acres by paying $405,000 in 2007 and $200,000 in 2008.

Drilling activities

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

Chase Group prior to the combination transaction on February 27, 2006. 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. Development wells are wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. Exploratory wells are 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. Productive wells are those that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

	Inception (April 21, 2004) through December 31, 2004		Years ended December 31, 2005		2006		Three months ended March 31, 2007	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development wells								
Productive	2.0	1.0	61.0	23.5	93.0	57.8	6.0	3.0
Dry	2.0	1.0	3.0	1.7	7.0	2.4		
Exploratory wells								
Productive	3.0	1.5	8.0	2.2	37.0	25.4	2.0	1.7
Dry	1.0	0.7	3.0	1.4	3.0	0.8	1.0	1.0
Total wells								
Productive	5.0	2.5	69.0	25.7	130.0	83.2	8.0	4.7
Dry	3.0	1.7	6.0	3.1	10.0	3.2	1.0	1.0
Total	8.0	4.2	75.0	28.8	140.0	86.4	9.0	5.7

As of March 31, 2007, we had 4.0 gross (3.9 net) wells that were in the process of drilling, all of which were exploratory wells.

As of March 31, 2007, we operated four rigs on our properties. While we have plans to add additional rigs during 2007, there can be no assurance that additional rigs will be available to us at an attractive cost or at times consistent with our 2007 drilling schedule. See Risk Factors Shortages of oil field equipment, services and qualified personnel could reduce our cash flow and adversely affect our results of operations.

We determined in January 2007 to reduce our drilling activities for the first three months of 2007. This determination was due to a decline in oil and natural gas prices in January 2007 compared to such prices in the fourth quarter of 2006, the costs of goods and services necessary to complete our drilling activities and the resulting effect of these circumstances on our expected cash flow for the three months ended March 31, 2007. This reduction in drilling activities will likely result in a reduction in oil and gas production, revenues and cash provided by operating activities for the year ended December 31, 2007. We resumed our planned drilling activities beginning in April 2007, and we believe we will spend our planned 2007 exploration and development budget of approximately $154 million during 2007.

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Our oil and natural gas reserves

The following table sets forth our estimated net proved oil and natural gas reserves, PV-10 and standardized measure of discounted future net cash flows as of December 31, 2006. PV-10 includes the present value of our estimated future abandonment and site restoration costs for proved properties net of the present value of estimated salvage proceeds from each of these properties. Our reserve estimates are based on independent engineering evaluations prepared by Netherland, Sewell & Associates, Inc. and Cawley Gillespie & Associates, Inc. as of December 31, 2006, ($57.75 per Bbl and $5.635 per MMBtu, adjusted for location and quality by field, were used in the computation of future net cash flows).

	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)	PV-10 ($MM)
Proved developed producing	21,032	101,544	227,736	$ 619.0
Proved developed non-producing	2,411	10,879	25,345	52.1
Proved undeveloped	20,879	88,395	213,669	282.9
Total proved	44,322	200,818	466,750	$ 954.0
Standardized measure of discounted future net cash flows(1)				$710.3

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

The following table sets forth our estimated net proved reserves and PV-10 as of December 31, 2006, by region:

	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)	Percent of total	PV-10 ($MM)
Permian Basin:					
Southeast New Mexico	35,084	177,005	387,509	83%	$ 782.6
West Texas	8,887	16,843	70,165	15%	154.5
Emerging Plays and Other	351	6,970	9,076	2%	16.9
Total	44,322	200,818	466,750	100%	$ 954.0

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Our production, prices and expenses

The following table sets forth summary information concerning our production results, average sales prices and production costs for the period from inception (April 21, 2004) through December 31, 2004, the years ended December 31, 2005 and 2006 and the three months ended March 31, 2006 and 2007. The actual historical data in this table excludes for periods prior to February 27, 2006, production from the oil and gas properties we acquired from the Chase Group in connection with the combination transaction. The pro forma data for the year ended December 31, 2006 and the three months ended March 31, 2006 gives effect to the oil and gas properties we acquired from the Chase Group as if we had acquired such properties on January 1, 2006.

	Inception (April 21, 2004) through December 31, 2004	Years ended December 31,		Year ended December 31,	Pro forma Three months ended March 31,	Three months ended March 31,	
		2005	2006	2006	2006	2006	2007
					(unaudited)	(unaudited)	(unaudited)
Net production volumes:							
Oil (MBbl)	44.7	599.0	2,294.8	2,539.6	557.1	312.3	708.9
Natural gas (MMcf)	290.7	3,403.8	9,506.8	10,497.6	2,404.9	1,414.1	2,952.2
Natural gas equivalent (MMcfe)	559.1	6,997.7	23,275.4	25,735.0	5,747.6	3,288.1	7,205.5
Average prices:							
Oil, without hedges ($/Bbl)	$ 41.37	$ 54.71	$ 60.47	$ 60.13	$ 56.83	$ 56.73	$ 54.09
Oil, with hedges ($/Bbl)	$ 41.37	$ 52.79	$ 57.42	$ 57.38	$ 54.47	$ 52.52	$ 55.54
Natural gas, without hedges ($/Mcf)	$ 6.09	$ 6.99	$ 6.87	$ 6.94	$ 7.10	$ 6.76	$ 7.06
Natural gas, with hedges ($/Mcf)	$ 6.09	$ 6.85	$ 7.00	$ 7.05	$ 6.97	$ 6.54	$ 7.10
Natural gas equivalent, without hedges ($/Mcfe)	$ 6.48	$ 8.08	$ 8.77	$ 8.76	$ 8.48	$ 8.29	$ 8.21
Natural gas equivalent, with hedges ($/Mcfe)	$ 6.48	$ 7.85	$ 8.52	$ 8.54	$ 8.20	$ 7.80	$ 8.37
Operating costs and expenses:							
Oil and gas production ($/Mcfe)	$ 0.92	$ 1.56	$ 0.95	$ 0.95	$ 1.10	$ 1.19	$ 1.01
Oil and gas production taxes ($/Mcfe)	$ 0.42	$ 0.53	$ 0.68	$ 0.68	$ 0.66	$ 0.60	$ 0.65
	$ 5.52	$ 1.15	$ 0.54	$ 0.50	$ 0.47	$ 0.74	$ 0.48

General and administrative ($/Mcfe)													
Depreciation and depletion expense ($/Mcfe)	$	1.71	$	1.64	$	2.61	$	2.57	$	2.20	$	2.20	$ 2.70

The following table sets forth information regarding our average daily pro forma production during the year ended December 31, 2006 and average daily production during the three months ended March 31, 2007, by geographic region:

	Pro forma average daily production for the year ended December 31, 2006			Average daily production for the three months ended March 31, 2007		
	Bbl	**Mcf**	**Mcfe**	**Bbl**	**Mcf**	**Mcfe**
Permian Basin						
Southeast New Mexico	5,465	23,950	56,740	6,102	27,229	63,841
West Texas	1,451	3,722	12,428	1,638	3,574	13,402
Emerging Plays and Other	40	1,088	1,328	137	1,999	2,821
Total	6,956	28,760	70,496	7,877	32,802	80,064

Summary of core operating areas and emerging plays

Permian Basin

The Permian Basin is one of the most prolific oil and gas regions in the United States, with its first commercial discovery in 1923 and cumulative production of 32.5 billion barrels of oil and 105 trillion cubic feet of gas as of December 31, 2006. Current average daily production in the Permian Basin is approximately 10 billion cubic feet equivalent gas per day from approximately 118,000 active producing wells. It underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from approximately 1,000 feet to over 25,000 feet. This area is characterized by long life shallow decline reserves.

The Permian Basin is our core operating area, and, as of December 31, 2006, our estimated net proved reserves of 464 Bcfe in this basin accounted for 99% of our total estimated net proved reserves and 99% of our PV-10. As of March 31, 2007, we owned an interest in 1,886 wells in the Permian Basin, of which we operated 920. Based on our total proved reserves as of December 31, 2006, and our pro forma 2006 production, our reserve to production ratio was 18.3 years. As of December 31, 2006, we identified 1,675 drilling locations, with proved undeveloped reserves attributed to 595 of such locations, and 538 recompletion opportunities, with proved reserves attributed to 221 of such opportunities. During the year ended December 31, 2006, our pro forma average net daily production in the Permian Basin was 69.3 MMcfe per day, and during the three months ended March 31, 2007, our average net daily production in the Permian Basin was 78.9 MMcfe per day.

Southeast New Mexico Permian

Our Permian Basin operations in Southeast New Mexico represent our most significant concentration of assets and, as of December 31, 2006, our estimated proved reserves of 387.5 Bcfe in this basin accounted for 83% of our total net proved reserves and 82% of our proved PV-10. As of December 31, 2006, the wells that we operated accounted for 92% of our proved PV-10 in this core area. As of March 31, 2007, we had 1,405 gross producing wells in Southeast New Mexico. During the three months ended March 31, 2007, our average net daily production from

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this area was approximately 65.5 MMcfe per day, representing 82% of our total production for that time period. 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 Morrow formation, with producing depths generally ranging from 7,500 feet to 15,000 feet.

Shelf Properties

Our Shelf Properties represented 75% of our total PV-10 as of December 31, 2006. We acquired most of these properties from the Chase Group upon closing of the combination transaction. As of December 31, 2006, we had 353.5 Bcfe of proved reserves and 1,137 gross producing wells in this area. As of March 31, 2007, we had 1,141 gross producing wells in this area. As of December 31, 2006, on our Shelf Properties, we identified 1,416 drilling locations, with proved undeveloped reserves attributed to 395 of such locations, and 452 recompletion opportunities, with proved reserves attributed to 155 of such opportunities. Average net daily production from this area for the three months ended March 31, 2007, was approximately 55.6 MMcfe per day, and production from this area represents 70% of our total average daily net production for the same period. Our properties are primarily located in Eddy and Lea counties, along the Abo-Yeso shelf edge on the northern rim of the Delaware Basin. This east to west trending fairway produces from a succession of stacked pays. The majority of the production in this region is from the Grayburg, San Andres and Yeso (Paddock and Blinebry intervals) formations. During 2006, we accelerated an evaluation, which had begun in late 2005, of the Blinebry interval of the Yeso formation, the top of which is located approximately 400 feet below the base of the Paddock interval of the Yeso formation. In 2006, we drilled 52 wells in the Blinebry interval, all of which have since been completed as producers. At December 31, 2006, the wells in the Blinebry interval which had been drilled and completed and were producing only from the Blinebry interval were producing an average of 80 Bbl and 176 Mcf per well per day. In 2007, we intend to drill 87 wells on our Shelf Properties, 73 of which will further evaluate the aerial extent of the Blinebry interval. The Empire/Empire East and Loco Hills fields collectively comprised 61% of our Southeast New Mexico PV-10 as of December 31, 2006.

Empire/Empire East. Producing intervals include the Yates, Morrow, Grayburg, Queen, Strawn, Wolfcamp, Seven Rivers, Yeso (Paddock and Blinebry intervals) and Abo formations. As of December 31, 2006, we had 167 Bcfe of proved reserves and 399 gross wells producing in the area. As of March 31, 2007, we had 400 gross producing wells in this area. In addition, as of December 31, 2006, we identified 511 drilling locations, with proved undeveloped reserves attributed to 153 of such locations, and 183 recompletion opportunities, with proved reserves attributed to 66 of such opportunities. As of December 31, 2006, proved reserves attributable to the Empire/Empire East field had a PV-10 of $373 million, which represented approximately 48% of the total PV-10 attributable to our entire Southeast New Mexico properties. Average net daily production for the three months ended March 31, 2007 was approximately 24.4 MMcfe.

Loco Hills. We are currently producing from the Seven Rivers, Queen, Grayburg, Morrow, Abo, San Andres and Yeso (Paddock and Blinebry intervals) formations. As of March 31, 2007, we had 185 gross producing wells in this field. In addition, as of December 31, 2006, we identified 246 drilling locations, with proved undeveloped reserves attributed to 70 of such locations, and 207 recompletion opportunities, with proved reserves attributed to 65 of such opportunities. As of December 31, 2006, reserves attributable to the Loco Hills field had a PV-10 of $204 million, which represented approximately 26% of the total PV-10 attributable to our Southeast New

Mexico properties. Average net daily production for the three months ended March 31, 2007 was approximately 18.4 MMcfe.

Basinal Properties

Our Basinal Properties in Southeast New Mexico represent approximately 7% of our total PV-10 as of December 31, 2006. As of December 31, 2006, we had 34 Bcfe of proved reserves and 259 gross wells producing in this area. As of March 31, 2007, we had 260 gross wells producing in this area. As of December 31, 2006, on our Basinal Properties, we identified 89 drilling locations, with proved undeveloped reserves attributed to 60 of such locations, and 37 recompletion opportunities, with proved reserves attributed to 32 of such opportunities. Average net daily production from this area for the three months ended March 31, 2007, was approximately 8.2 MMcfe per day, and production from this area represents 10% of our total average daily net production for the same period. The majority of the production in this region is from the Morrow formation, with significant additional contributions from the shallower Atoka and Strawn formations. In 2007, we intend to drill or participate in five wells to the Morrow formation and drilled 10 such wells in 2006, with seven wells producing, two wells awaiting completion and one dry hole.

Texas Permian

This core area accounted for approximately 15% of our total proved reserves and approximately 16% of our total PV-10 as of December 31, 2006. As of December 31, 2006, we had 70 Bcfe of proved reserves and 480 gross wells producing in this area. As of March 31, 2007, we had 481 gross wells producing in this area. In addition, as of December 31, 2006, we identified 148 drilling locations, with proved undeveloped reserves attributed to 127 of such locations, and 49 recompletion opportunities, with proved reserves attributed to 34 of such opportunities. In 2007, we intend to drill 20 wells in this area. As of December 31, 2006, approximately 52% of the total PV-10 attributable to our Texas Permian core area was concentrated in the area s three most significant fields. Two of the top three fields (Fullerton and Deep Rock) are located on the Central Basin Platform, while the third (Coyanosa) is located just off the western edge of the platform.

Fullerton. Our interests in this field consist of 29 wells producing from the Clearfork formation. In addition, as of December 31, 2006, we identified 30 drilling locations, with proved reserves attributed to 24 of such locations. The PV-10 of our proved reserves in this field as of December 31, 2006, was $39 million. This field represents approximately 25% of the total PV-10 attributable to our Texas Permian core area and contained 16.8 Bcfe of proved reserves as of December 31, 2006. Average net daily production for the three months ended March 31, 2007 was approximately 3.2 MMcfe.

Deep Rock. Our interests in this field consist of 35 wells producing from multiple intervals, including the Ellenberger, Devonian, Pennsylvanian, Wolfcamp and Glorieta formations, at depths ranging from 3,500 feet to 10,000 feet. In addition, as of December 31, 2006, we identified 14 drilling locations, with proved undeveloped reserves attributable to 11 of such locations, and one recompletion opportunity. The PV-10 of our proved reserves in this field as of December 31, 2006, was $30 million. This field represents approximately 20% of the total PV-10 attributable to our Texas Permian core area and contains 15.1 Bcfe of proved reserves as of December 31, 2006. Average net daily production for the three months ended March 31, 2007 was approximately 2.0 MMcfe.

Coyanosa. Our interests in this field consist of 51 wells producing from multiple intervals, including the Ellenberger, Wolfcamp or Delaware formations, at depths ranging from 3,500 feet to 18,000 feet. In addition, as of December 31, 2006, we identified two drilling locations, with proved reserves attributed to one of such locations, and 25 recompletion opportunities, with proved reserves attributed to 19 of such opportunities. The PV-10 of our proved reserves in this field as of December 31, 2006, was $12 million. This field represents approximately 8% of the total PV-10 attributable to our Texas Permian core area and contains 4.9 Bcfe of proved reserves as of December 31, 2006. Average net daily production for the three months ended March 31, 2007 was approximately 1.8 MMcfe.

Emerging Resource Play Areas

As of March 31, 2007, we were involved in six significant unconventional emerging resource plays, with a total acreage position of 229,150 gross (124,448 net) acres. These plays are currently in various stages of maturity. As of December 31, 2006, we had an aggregate of 6.0 Bcfe of proved reserves attributed to these plays.

Southeast New Mexico

A horizontal Wolfcamp play is being actively exploited along the northwestern rim of the Delaware Basin, in Eddy and Chaves Counties, New Mexico, with several operators flowing gas to sales. This Wolfcamp horizon is found at depths ranging from 4,100 feet to 6,000 feet. We have tested one re-entry, and have participated with Mack Energy Corporation in the drilling of six horizontal exploration wells. As of March 31, 2007, we owned 53,618 gross (21,235 net) acres, of which we acquired 24,579 gross (6,138 net) acres in the play from Caza Energy, LLC, a Chase Oil affiliate, subsequent to the combination transaction.

In addition, during the fourth quarter of 2006, we drilled one horizontal test well in the oil window of the Wolfcamp horizon and completed such well as a producer in mid-February 2007. Through April 30, 2007, this well averaged approximately 1.9 MMcfe per day.

As of December 31, 2006, we had 5.9 Bcfe of proved reserves booked to the horizontal Wolfcamp play in Eddy and Chaves Counties, New Mexico.

Central Basin Platform

In November 2006, we acquired 9,548 gross (9,548 net) acres in the Woodford Shale play in Andrews County, Texas. This unconventional shale is prospective at depths from 8,000 to 10,000 feet. We currently plan to drill our first test well in 2007.

Western Delaware Basin

This play is located in West Texas in a lightly explored portion of the Delaware Basin. As of March 31, 2007, we owned 68,814 gross (22,794 net) acres in Culberson and Reeves Counties, Texas. Both conventional and unconventional targets are prospective in this area. We have drilled and are in different stages of completing four exploratory wells. The primary unconventional targets are the Bone Spring, Atoka, Barnett and Woodford Shales, which are found at depths ranging from 5,000 feet to 12,000 feet.

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Val Verde Basin

As of March 31, 2007, we owned 39,999 gross (39,609 net) acres in this play located in Edwards and Kinney Counties, Texas, where the primary unconventional targets are the fractured Ellenburger Dolomite and the Canyon Sands at depths of less than 8,000 feet. We currently plan to conduct a 3-D seismic survey of this play in the second quarter of 2007 and to drill our first test well in the fourth quarter of 2007.

North Dakota

This horizontal Bakken Shale play is being developed in the North Dakota portion of the Williston Basin. This Mississippian age horizon consists of a siltstone encased within a highly organic oil-rich shale package and is found at depths ranging from 9,000 feet to 11,000 feet. We have completed two wells as producers. As of March 31, 2007, we owned 40,149 gross (16,810 net) acres in this play in Mountrail and McKenzie Counties, North Dakota. As of December 31, 2006, we had 0.1 Bcfe of proved reserves booked to this play.

Arkansas

As of March 31, 2007, we owned 17,022 gross (14,452 net) acres in the Fayetteville Shale play in Faulkner and White Counties, Arkansas. The Fayetteville Shale play in the eastern Arkoma Basin of Arkansas is the geological time equivalent to the Barnett Shale, a proved target in the Ft. Worth Basin. The Fayetteville Shale has producers in both vertical and horizontal wells, and on our acreage position the Fayetteville Shale is found at depths ranging from 7,000 feet to 8,500 feet.

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 the 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. The majority of our crude oil is transported by truck to various pipeline stations throughout Southeast New Mexico and West Texas. The oil is then delivered either to hub facilities located in Midland, Texas or Cushing, Oklahoma or to third party refineries located in Southeast New Mexico and the panhandle of Texas, with the majority of our crude oil going to a refinery in Southeast New Mexico. The remaining oil that we produce is connected directly to pipelines via gathering facilities in the respective field locations. 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. Approximately 36% of our oil and natural gas revenues for the year ended December 31, 2006, were attributable to a verbal agreement with Navajo Refining Company, L.P., an arrangement pursuant to which crude oil production attributable to the properties located in Southeast New Mexico that we acquired in the combination transaction has been marketed for several years. We entered into an agreement as of January 1, 2007 with Navajo Refining Company, L.P. that sets forth in writing the fundamental terms of the verbal agreement under which we had previously conducted business with that purchaser. The agreement with Navajo Refining Company, L.P. sets forth the applicable market-based pricing metric for specific leases. The agreement currently runs on a 30-day evergreen basis and is terminable by either party upon 30-day advanced written notice. The majority of our contracts are based on a Platt s formula which is calculated based on an intermediate posting deemed 40 degrees (typically as published by major crude oil purchasers at the Cushing, Oklahoma delivery point) for each calendar month plus the average of the Platt s P-Plus WTI price as published monthly in the Platt s Oilgram Price Report. This price is then adjusted for differentials based upon delivery location and oil quality. We also sell a portion of our oil at prices posted by the principal purchaser of oil where our producing properties are located.

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

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

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

Our principal customers

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

On a pro forma basis (assuming the combination transaction took place on January 1, 2006), for the year ended December 31, 2006, revenues from oil and natural gas sales to Navajo Refining Company, L.P. and DCP Midstream, LP, formerly Duke Energy Field Services, accounted for approximately 53% and 18%, respectively, of our total operating revenues. While the loss of

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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 a number of 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 leases, 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 is currently experiencing shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which has delayed developmental drilling and exploitation activities and caused significant price increases. The 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 when, or if, such shortages may be alleviated.

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

Applicable laws and regulations

Regulation of the oil and natural gas industry

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

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be 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 (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

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

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

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

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

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

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

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

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

Environmental, health and safety matters

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

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

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

The following is a summary of some of the existing laws, rules and regulations to which our business operations are subject.

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 exploitation 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.

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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 actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. For instance, at least nine states in the Northeast (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York and Vermont) and five states in the West (Arizona, California, New Mexico, Oregon and Washington) have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court s decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S., or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our products.

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

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

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2006. Additionally, as of the date of this prospectus, we are not aware of any environmental issues or claims that will require material capital expenditures during 2007. However, we cannot assure you that the passage of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operation. For instance, the New Mexico Oil Conservation Division is considering amending or replacing an existing rule regulating the permitting, construction, operation and closure of oilfield pits at well sites in New Mexico. If the agency adopts a new or revised pit rule that imposes stricter requirements on the construction and use of oilfield pits, then it is possible that the cost to operate our wells in New Mexico could increase.

Grayburg-Jackson West Cooperative Unit Regulatory Matter

From 1984 through 1997, the owners of the Grayburg-Jackson West Cooperative Unit (which is referred to herein as the GJ Unit), a group of formations and intervals unitized by state regulatory authorities, compromised of approximately 2,400 acres in Eddy County, New Mexico and which comprises a portion of the Chase Group Properties, drilled or deepened approximately 70 wells that produced from zones below a depth approved as the unitized formation. The owners of the working interests in the GJ Unit possessed the ownership rights entitling them to produce hydrocarbons from the subject producing intervals below the unitized formation, but had not obtained the necessary regulatory approval (1) as to certain wells, to drill or deepen below the base of the unitized formation or (2) to produce hydrocarbons from intervals below the base of the unitized formation and to commingle such production with production from the unitized formation. In connection with the failure to obtain the required regulatory approval to produce on a commingled basis from these deeper intervals, the operators filed incorrect perforation and completion reports with state regulatory authorities, and filed monthly production reports that did not disclose that hydrocarbons had been produced from intervals below the unitized formation and that hydrocarbons produced from these deeper intervals were improperly commingled with production from the unitized formation (although the reports apparently reflected the actual volumes produced by the wells). As a result, a unit royalty interest owner in the unitized formation was overpaid and the State of New Mexico, which was the owner of the royalty interest in the subject producing intervals below the unitized formation, was underpaid for several years.

On November 15, 2005, Mack Energy Corporation filed an application with the New Mexico Oil Conservation Division (which is referred to herein as the NMOCD) to expand the vertical limit of the unitized formation to include the deeper intervals that had been accessed, produced and commingled without obtaining regulatory approval. A hearing on the application was originally scheduled for December 15, 2005, but was continued at the request of Mack Energy. On February 27, 2006, the combination transaction occurred and, as a result, we acquired the GJ Unit.

On April 13, 2006, the NMOCD held a hearing on Mack Energy s application to expand the vertical limit of the unitized formation. Representatives of Mack Energy, acting under our Contract Operator Agreement with Mack Energy, participated in the hearing and presented testimony during that hearing that intervals below the unitized formation had not been tested or developed. Based on the application submitted by Mack Energy and the evidence and testimony presented at the hearing, on June 13, 2006, the NMOCD approved the application and entered its order expanding the vertical limit of the unitized formation to include certain deeper intervals, including one of those that had previously been produced and commingled without regulatory approval.

Over the course of developing our drilling program for the Chase Group Properties in July and August 2006, we discovered the existence of these violations and this testimony. Following further investigation by our employees and discussions with a representative of Chase Oil and Mack Energy and our counsel, we reported these developments to our board of directors. Because this matter related to ongoing regulatory violations by entities that were under the control of certain members of our board of directors, our board of directors determined on September 6, 2006, to form a special committee of the board of directors that consisted of independent and disinterested non-management directors for the purpose of investigating the matters identified by our management relating to the GJ Unit. The special committee engaged separate legal counsel to assist it with its investigation of this matter. Also, in September 2006, representatives of Mack Energy and our company met with relevant regulatory authorities from the State of New Mexico, and voluntarily self-reported the matters related to the GJ Unit, and we filed amended reports to correct prior reporting inaccuracies.

As a result of these actions, we, along with Mack Energy, entered into a settlement agreement with the New Mexico State Land Office on November 2, 2006 related to the underpayment of royalties arising from these circumstances. Under the terms of the settlement agreement, Mack Energy paid $615,444 to the State of New Mexico for underpayment of royalties and interest thereon. We were not required to make any payments under the settlement agreement. Further, on January 22, 2007, the State of New Mexico advised us that there was no basis for a compliance and enforcement proceeding against our company and no evidence of a knowing and willful violation of applicable law by our company. On January 19, 2007, Mack Energy entered into an Agreed Compliance Order and agreed to pay a penalty of $250,000 for its violations of applicable rules, regulations and statutes. Finally, the NMOCD approved our correction of the prior records related to the GJ Unit and, in February 2007, approved our application to expand the vertical limit of the unitized formation below the depth of the intervals that had previously been improperly produced and commingled with production from the unitized formation and to bring all of the wells in the GJ Unit into compliance with all applicable rules, regulations and statutes.

The special committee of the board of directors examined relevant documents provided by our company and our regulatory counsel in New Mexico, conducted interviews of members of management and heard a presentation from a representative of Chase Oil and Mack Energy. The special committee also monitored the activities of our company and our legal counsel during the discussions and proceedings with relevant New Mexico regulatory authorities. Based on its review of this matter, the special committee recommended the adoption of certain policies and procedures governing the operation of all legal proceedings involving our company as well as a review of the due diligence processes associated with future acquisitions of properties. The special committee also recommended certain actions to address corporate governance matters at our company. Finally, the special committee reviewed the conduct of our officers and directors to determine whether any such conduct would indicate that an officer or director was unsuitable to continue in their position, and the special committee did not determine that any officer or director was unsuitable to continue in their position with our company.

Legal proceedings

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

Title to our properties

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

Our employees

As of March 31, 2007, we employed 80 employees, including 19 employed in drilling and production, 15 in financial and accounting, 16 in land, 14 in exploration, 6 in reservoir engineering and 10 in administration. Of these, 73 worked in our Midland, Texas headquarters and 7 were in our field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Management

Executive officers and directors

The following table sets forth names, ages and titles of our executive officers and directors as of May 31, 2007:

Name	Age	Title
Timothy A. Leach	47	Chairman of the Board, Chief Executive Officer and Director
Steven L. Beal	48	President, Chief Operating Officer and Director
David W. Copeland	50	Vice President, General Counsel and Secretary
Curt F. Kamradt	44	Vice President, Chief Financial Officer and Treasurer
David M. Thomas III	52	Vice President Exploration and Land
E. Joseph Wright	47	Vice President Engineering and Operations
Jack F. Harper	36	Vice President Business Development and Capital Markets
Tucker S. Bridwell	55	Director
W. Howard Keenan, Jr.	56	Director
A. Wellford Tabor	38	Director

Timothy A. Leach has been the Chairman of the Board of Directors and Chief Executive Officer of our company since its formation in February 2006. Mr. Leach has been the Chairman of the Board and Chief Executive Officer of Concho Equity Holdings Corp. since its inception in April 2004. Mr. Leach was Chairman of the Board and Chief Executive Officer of Concho Oil & Gas Corp. from its inception in January 2001 until its sale in January 2004. From January 2004 to April 2004, Mr. Leach was involved in private investments. Mr. Leach was Chairman of the Board of Directors and Chief Executive Officer of Concho Resources Inc. (which was a different company than our company) from its inception in August 1997 until its sale in June 2001. From September 1989 until May 1997, Mr. Leach was employed by Parker & Parsley Petroleum Company (now Pioneer Natural Resources Company) in a variety of capacities, including serving as Executive Vice President and as a member of Parker & Parsley s Executive Committee. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

Steven L. Beal has been a Director and the President and Chief Operating Officer of our company since its formation in February 2006. Mr. Beal has been a director and the President and Chief Operating Officer of Concho Equity Holdings Corp. since its inception in April 2004. Mr. Beal was a director and the Executive Vice President and Chief Financial Officer of Concho Oil & Gas Corp. from its inception in January 2001 until he became its President and Chief Operating Officer in August 2002, a position he held until its sale in January 2004. From January 2004 to April 2004, Mr. Beal was involved in private investments. Mr. Beal was a director and the Vice President and Chief Financial Officer of Concho Resources Inc. (which was a different company than our company) from its inception in August 1997 until its sale in June 2001. From October 1988 until May 1997, Mr. Beal was employed by Parker & Parsley Petroleum Company (now Pioneer Natural Resources Company) in a variety of capacities, including serving as its Senior Vice President and Chief Financial Officer and as a member of Parker & Parsley s Executive Committee. From 1981 until February 1988, Mr. Beal was employed by the accounting firm of

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Price Waterhouse. He is a graduate of the University of Texas with a Bachelor of Business Administration degree in Accounting and is a certified public accountant.

David W. Copeland has been Vice President General Counsel and corporate Secretary of our company since its formation in February 2006. Mr. Copeland has been the Vice President General Counsel and corporate Secretary of Concho Equity Holdings Corp. since its inception in April 2004. Mr. Copeland was a director and the Executive Vice President General Counsel and corporate Secretary of Concho Oil & Gas Corp. from its inception in January 2001 until its sale in January 2004. From January 2004 to April 2004, Mr. Copeland was involved in private investments. Mr. Copeland was a director and the Vice President General Counsel and Corporate Secretary of Concho Resources Inc. (which was a different company than our company) from its inception in August 1997 until its sale in June 2001. From 1991 until June 1997, Mr. Copeland was employed in the Legal Department of Parker & Parsley Petroleum Company (now Pioneer Natural Resources Company), and served as Vice President, Associate General Counsel from 1994 until June 1997. Prior to joining Parker & Parsley, Mr. Copeland was a partner with the Midland, Texas law firm of Stubbeman, McRae, Sealy, Laughlin & Browder, where his practice was concentrated in corporate, banking and other commercial matters. He is a graduate of Midwestern State University with a Bachelor of Business Administration and a graduate of Texas Tech University School of Law with a Doctor of Jurisprudence.

Curt F. Kamradt has been the Vice President Chief Financial Officer and Treasurer of our company since its formation in February 2006. Mr. Kamradt has been the Vice President Chief Financial Officer and Treasurer of Concho Equity Holdings Corp. since its inception in April 2004. Mr. Kamradt was Vice President Chief Accounting Officer and Treasurer of Concho Oil & Gas Corp. from its inception in January 2001 until he became its Vice President and Chief Financial Officer in August 2002, a position he held until its sale in January 2004. From January 2004 to April 2004, Mr. Kamradt was involved in private investments. Mr. Kamradt was the Treasurer of Concho Resources Inc. (which was a different company than our company) from February 1999 until its sale in June 2001. From December 1989 until October 1998, Mr. Kamradt was employed by Parker & Parsley Petroleum Company (now Pioneer Natural Resources Company) in a variety of capacities, including serving as its Treasurer. From 1985 until December 1989, Mr. Kamradt was employed by the accounting firms of Price Waterhouse and Grant Thornton. He is a graduate of Eastern New Mexico University with a Bachelor of Business Administration degree in Accounting and is a certified public accountant.

David M. Thomas III has been the Vice President Exploration and Land of our company since its formation in February 2006. Mr. Thomas has been the Vice President Exploration & Land of Concho Equity Holdings Corp. since April 2005. From July 2004 until April 2005, Mr. Thomas was involved in private investments. From August 2000 to July 2004, Mr. Thomas served as Exploration Manager/Southern Region for Tom Brown, Inc. In 2000, prior to joining Tom Brown, Inc., he served as a geologist for Pure Resources Inc. From 1998 to 2000, he served as Senior Staff Geologist for Mobil E&P U.S. Inc. and Senior Geologist for Conoco, Inc. in Midland, Texas. Mr. Thomas is certified as a Professional Geoscientist and is a Certified Professional Landman. He is a graduate of the University of New Mexico with a Bachelor of Business Administration degree, and a graduate of the University of Oklahoma with a Master of Science degree in Geology.

E. Joseph Wright has been the Vice President Engineering and Operations of our company since February 2006. Mr. Wright has been the Vice President Operations & Engineering of Concho Equity Holdings Corp. since its inception in April 2004. Mr. Wright was Vice President

Operations/Engineering of Concho Oil & Gas Corp. from its inception in January 2001 until its sale in January 2004. From January 2004 to April 2004, Mr. Wright was involved in private investments. Mr. Wright served in various engineering and operations positions for Concho Resources Inc. (which was a different company than our company), including serving as Vice President Operations, from February 1998 until its sale in June 2001. From 1982 until February 1998, Mr. Wright was employed by Mewbourne Oil Company in several operations, reservoir and evaluation engineering and capital markets positions. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

Jack F. Harper has been the Vice President Business Development and Capital Markets of our company since May 2007. Mr. Harper was the Director of Investor Relations and Business Development of our company from July 2006 until May 2007. From October 2005 until July 2006, Mr. Harper was involved in private investments. From October 2002 until October 2005, Mr. Harper was employed by Unocal Corporation where he served as Manager of Planning and Evaluation and Manager of Business Development for Unocal Corporation s wholly owned subsidiary, Pure Resources. From May 2000 until October 2002, Mr. Harper was employed by Pure Resources, Inc. in a variety of capacities, including in his last position as Vice President, Finance and Investor Relations. From December 1996 until May 2000, Mr. Harper was employed by Tom Brown, Inc., where his last position was Vice President, Investor Relations, Corporate Development and Treasurer. He is a graduate of Baylor University with a BBA degree in Finance.

Tucker S. Bridwell has been a Director of our company since February 2006. Mr. Bridwell was a director of Concho Equity Holdings Corp. from its inception in April 2004 until February 2006, and served as Chairman of its Compensation Committee. Mr. Bridwell has been the President of each of the Mansefeldt Investment Corporation and the Dian Graves Owen Foundation since September 1997 and manages investments for both entities; both of which are stockholders of our company. He has been in the energy business in various capacities for over twenty-five years. Mr. Bridwell served as Chairman of the Board of Directors of First Permian, LLC from 2000 until its sale to Energen Corporation in April 2002. Mr. Bridwell is also a director of Petrohawk Energy Corporation and serves on its Audit Committee. He is a graduate of Southern Methodist University with a Bachelor of Business Administration degree and a Master of Business Administration degree, and is a certified public accountant.

W. Howard Keenan, Jr. has been a Director of our company since February 2006. Mr. Keenan previously was a director of Concho Equity Holdings Corp., Concho Oil & Gas Corp. and Concho Resources Inc. (which was a different company than our company). Mr. Keenan has over thirty years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private equity investment manager focused on the energy industry. Two limited partnerships managed by Yorktown Partners LLC are stockholders of our company. Mr. Keenan currently serves on the Board of Directors of GeoMet, Inc. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown Partners portfolio companies. Mr. Keenan holds a Bachelors degree from Harvard College and a Master of Business Administration from Harvard University.

A. Wellford Tabor has been a Director of our company since February 2006. Mr. Tabor was a director of Concho Equity Holdings Corp. from its inception in April 2004 until February 2006. Mr. Tabor also served as a director of Concho Oil & Gas Corp. from March 2003 until its sale to a large domestic independent oil and gas company in January 2004. Mr. Tabor is a Partner with

Wachovia Capital Partners, which is a stockholder of our company. Prior to joining Wachovia Capital Partners in 2000, Mr. Tabor was a director at The Beacon Group from 1995 to 2000. From 1991 to 1993, he worked in the Investment Banking Division at Morgan Stanley & Co. Mr. Tabor currently serves on the Board of Directors of James River Specialty, a publicly traded insurance company, and several other privately held energy and financial services companies in which Wachovia Capital Partners is an investor. Mr. Tabor earned his undergraduate degree from The University of Virginia and his Master of Business Administration from The Graduate School of Business at Stanford University.

Board of directors

We currently have five directors. Our restated certificate of incorporation and bylaws will provide for a classified board of directors consisting of three classes of directors, each serving staggered three-year terms. As a result, stockholders will elect a portion of our board of directors each year. Class I directors terms will expire at the annual meeting of stockholders to be held in 2008, Class II directors terms will expire at the annual meeting of stockholders to be held in 2009 and Class III directors terms will expire at the annual meeting of stockholders to be held in 2010. The Class I directors are Messrs. Leach and Keenan, the Class II directors are Messrs. Beal and Bridwell and the Class III director is Mr. Tabor. At each annual meeting of stockholders held after the initial classification, the successors to directors whose terms will then expire will be elected to serve from the time of election until the third annual meeting following election. The division of our board of directors into three classes with staggered terms may delay or prevent a change of our management or a change in control. See Description of capital stock Anti-takeover provisions of our certificate of incorporation and bylaws.

In addition, our restated bylaws will provide that the authorized number of directors, which shall constitute the whole board of directors, may be changed by a resolution duly adopted by the board of directors. Any additional directorships resulting from an increase in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of one-third of the total number of directors. Vacancies and newly created directorships may be filled by the affirmative vote of a majority of our directors then in office, even if less than a quorum.

Each of our current directors was nominated in accordance with provisions of a stockholders agreement and a voting agreement entered into at the time of the combination transaction. These stockholders agreement and voting agreement provisions will automatically terminate upon the closing of this offering.

Board committees

Our board of directors currently has an audit committee and a compensation committee. Following the closing of this offering, we intend to actively recruit additional directors to serve on our board of directors. We expect that these additional directors will qualify as independent for purposes of serving on our board of directors. In addition, our board of directors intends to form a nominating and corporate governance committee upon the completion of this offering.

Audit committee. Our audit committee currently consists of Messrs. Tabor, Keenan and Bridwell. Mr. Tabor is independent under the standards of the New York Stock Exchange and SEC regulations. As permitted by the standards of the New York Stock Exchange and the rules of the

SEC, we intend to appoint an independent director to replace Mr. Keenan on the audit committee within 90 days of the completion of this offering and a second independent director to replace Mr. Bridwell on the audit committee within one year of the completion of this offering. Our audit committee operates pursuant to a formal written charter. This committee oversees, reviews, acts on and reports to our board of directors on various auditing and accounting matters, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements.

Compensation committee. Our compensation committee currently consists of Messrs. Bridwell and Keenan, with Mr. Bridwell serving as chairman of the compensation committee. Messrs. Bridwell, and Keenan are independent under the standards of the New York Stock Exchange and SEC regulations. As required by the standards of the New York Stock Exchange, the compensation committee consists solely of independent directors. Our compensation committee operates pursuant to a formal written charter. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee also administers our incentive compensation and benefit plans.

Compensation committee interlocks and insider participation

The compensation committee consists of Messrs. Bridwell and Keenan, both of whom are non-employee directors, with Mr. Bridwell serving as chairman of the compensation committee. Neither of these individuals have ever been an officer or employee of our company. In addition, none of our executive officers serves as a member of a board of directors or compensation committee of any entity that has one or more executive officers who serve on our board or on our compensation committee.

Executive officer compensation

Compensation discussion and analysis

This compensation discussion and analysis explains our compensation philosophy, policies and practices with respect to our chief executive officer, chief financial officer and the other four most highly-compensated executive officers, which are collectively referred to as our named executive officers.

General. Our compensation committee is responsible for establishing and administering policies governing the compensation of our named executive officers. The compensation committee is composed entirely of independent directors. See Board committees Compensation committee.

Our executive compensation program is designed to accomplish the following objectives:

- attract individuals with the skills necessary for us to execute our business plan;
- motivate and reward executive officers whose knowledge, skills and performance are critical to our success;
- align the interests of our named executive officers and stockholders with the performance of our company on both a short-term and long-term basis; and

retain those individuals who continue to perform at or above the levels that we expect.

To accomplish these objectives, we provide what we believe is a competitive total compensation package to our executive management team through a combination of base salary, annual cash bonuses, long-term equity incentive compensation and broad-based benefits programs.

Our compensation committee determines the appropriate level for each compensation component based on competitive benchmarking, our recruiting and retention goals, our view of internal parity and consistency and overall company performance. When our compensation committee established our named executive officers compensation levels for 2006, it reviewed compensation data in an executive compensation survey of energy companies prepared by Mercer Human Resource Consulting, Inc. We believe that the group of companies participating in the survey is an appropriate peer group because it consists of similar organizations against whom we compete for executive talent. Our compensation committee has not engaged a compensation consultant in the past, but we engaged Longnecker & Associates in March 2007 to assist with the evaluation of our executive compensation program going forward. Our compensation committee has not adopted any formal or informal policies or guidelines for allocating compensation between long-term and currently paid out compensation, between cash and non-cash compensation or among different forms of non-cash compensation.

In connection with becoming a public company, our compensation committee s intent is to perform at least annually a strategic review of our named executive officers overall compensation package to determine whether it provides adequate incentives and motivation and whether it adequately compensates our named executive officers relative to comparable officers in other companies with which we compete for executives. After our initial public offering, we anticipate working with Longnecker & Associates to conduct a review of our named executive officers overall compensation package for the remainder of 2007 and for 2008. The compensation committee meets outside the presence of all of our named executive officers to consider appropriate compensation for our chief executive officer and our president. For all other named executive officers, our compensation committee meets outside the presence of all named executive officers except our chief executive officer and president. Our chief executive officer and president together annually review other named executive officers performance with our compensation committee and make recommendations with respect to the appropriate base salary, targets for and payments under our annual cash bonus plan and the grants of long-term equity incentive awards for those named executive officers. Based in part on these recommendations from our chief executive officer and president and other considerations discussed below, the compensation committee establishes and approves the annual compensation package of our named executive officers other than our chief executive officer and president.

Base compensation. On an annual basis, the compensation committee reviews salary ranges and individual salaries for our named executive officers. We seek to pay base salaries at the market median pay level of individuals in comparable positions. We believe that paying base salaries at the market median is necessary to achieve our compensation objectives of attracting and retaining executives with the appropriate abilities and experience required to lead us. The compensation committee established base salary for each named executive officer based on consideration of market median pay levels and internal factors, such as the individual s responsibilities, skills and experience, and the pay of others on the executive team.

In connection with the combination transaction, each of our named executive officers entered into a separate employment agreement, under which Messrs. Leach and Beal are guaranteed a minimum base annual salary of $350,000 and Messrs. Copeland, Kamradt, Wright and Thomas

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are guaranteed a minimum base annual salary of $250,000. Our compensation committee believes that these base salary levels achieve its executive compensation objectives and satisfy the goal of providing base salaries at the market median.

From January 1, 2006 until the completion of the combination transaction on February 27, 2006, our named executive officers received compensation as officers of Concho Equity Holdings Corp., our predecessor for accounting purposes. Base salary levels for our named executive officers during that period remained the same as in 2005 and consisted of $50,000 for each of Messrs. Leach and Beal and $33,333 for each of Messrs. Copeland, Kamradt, Wright and Thomas.

Cash bonuses. We utilize cash bonuses to reward achievement of performance targets with a time horizon of one year or less. Our compensation committee plans to determine performance targets for our named executive officers on an annual basis. We believe that the payment of cash bonuses upon the achievement of performance targets is necessary to achieve our compensation objectives of motivating and rewarding our named executive officers, as well as aligning the interests of our named executive officers and stockholders with the performance of our company on a short-term basis.

For 2006, the only performance target established by our compensation committee was the filing of the registration statement for our initial public offering. As this performance target was not achieved in 2006, none of our named executive officers received a cash bonus. In connection with the filing of the registration statement for our initial public offering in April 2007, Messrs. Leach and Beal each received a $313,000 cash bonus; Messrs. Copeland, Kamradt and Wright each received a $172,000 cash bonus; and Mr. Thomas received a $199,000 cash bonus. In determining the amount of this cash bonus for each of our named executive officers, the primary factors considered by our compensation committee were each named executive officer s overall responsibility for the management of our company and the process associated with our initial public offering and each named executive officer s overall prior investment in our securities (including the debt obligations incurred by each named executive officer in connection with such investment). Ultimately, the compensation committee exercised its discretion in determining the amount of the cash bonus.

For 2007, and in addition to the bonus payable upon the filing of the registration statement for our initial public offering, our named executive officers are eligible to earn a bonus ranging from 0% to 100% of their base salary based on the performance measure of net asset value per share growth, in addition to other performance measures that the committee may decide to evaluate in its sole discretion. When evaluating net asset value per share growth, our compensation committee has wide discretion to determine the appropriate percentage of base salary for each named executive officer. Our compensation committee chose net asset value per share growth because it believes it to be the best indicator of the Company s financial success and stockholder value creation.

Stock options. We utilize stock option grants to motivate and reward our named executive officers, as well as to align the interests of our named executive officers and stockholders with the performance of our company on a long-term basis. In addition, we utilize multi-year vesting periods when granting stock options to facilitate the compensation objective of retaining our named executive officers.

Typically, our stock options vest at a rate of one-quarter of the shares subject to the option on each of the first four anniversaries of the grant date. The stock options that we have granted under our 2006 Stock Incentive Plan typically may be exercised by the recipient at any time once vested and will expire ten years from the date of the grant, but may expire earlier upon termination of employment. While the 2006 Stock Incentive Plan allows for other forms of equity compensation, the compensation committee and management currently believe that stock options are the appropriate vehicle to provide long-term incentive compensation to our named executive officers. Other types of long-term equity incentive compensation may be considered in the future as our business strategy evolves.

Following the completion of our initial public offering, all options will be granted with an exercise price equal to the fair market value of our common stock on the date of the grant. Such fair market value will be defined as the closing market price of a share of our common stock on the date of the grant. We do not have any program, plan or practice of setting the exercise price on a date or price other than the fair market value of our common stock on the grant date. We do not have any program, plan or obligation that requires us to grant equity compensation on specified dates to our named executive officers.

Like other pay components, long-term equity incentive award grants are determined based on an analysis of competitive market data of companies we deem our peers, relying on data in the Mercer executive compensation survey. Annual grants are targeted at the median level of market pay practices for each executive officer s position, but may be adjusted based on individual performance. In addition, our compensation committee generally considers an executive officer s stock holdings or previous stock option grants when determining the number of stock options to be granted.

During 2006, we granted options to purchase 125,000 shares of our common stock to each of Messrs. Leach and Beal, and 150,000 shares to each of Messrs. Copeland, Kamradt and Wright, and 200,000 shares to Mr. Thomas. Each of the grants had an exercise price of $6.00 per share. These grants were made by our board of directors after the completion of the combination transaction in February 2006, and the board determined that, in light of the individuals performance, it was appropriate to provide additional incentive for each of these persons. In determining the number of shares subject to these option grants, the primary factor considered by our compensation committee was the prior investment by our named executive officers in our securities. As such, the compensation committee decided to award additional equity to certain of our named executive officers who had previously made smaller investments in our securities in an effort to more closely balance the equity ownership of our named executive officers. Ultimately, the compensation committee exercised its discretion in determining the number of shares subject to these option grants.

Stock ownership guidelines have not been implemented by our compensation committee for our named executive officers. We will continue to periodically review best practices and re-evaluate our position with respect to stock ownership guidelines.

Severance and change of control payments. All of our named executive officers are entitled to receive severance payments equal to a specified number of months of base salary, as well as accelerated vesting of all existing stock options in the event that their employment is terminated by our company other than for cause (and not by reason of death or disability) or if they terminate their employment following a change in duties. Upon a termination within two years of a change of control, each of our named executive officers is entitled to a lump sum severance payment equal to two years of base salary and accelerated vesting of all existing stock option awards.

We believe these severance and change of control arrangements mitigate some of the risk that exists for executives working in a smaller company. These arrangements are intended to attract and retain qualified executives that could have job alternatives that may appear to them to be less risky absent these arrangements. Because of recent significant acquisition activity in the oil and gas industry, there is a possibility that we could be acquired in the future. Accordingly, we believe that the larger severance packages resulting from terminations related to change of control transactions would provide an incentive for these executives to continue to help successfully execute such a transaction from its early stages until closing.

For a description and quantification of these severance and change of control benefits, please see Employment, severance and change of control arrangements.

Other benefits. Our named executive officers are eligible to participate in all of our employee benefit plans, such as medical, dental, vision, group life, disability, and accidental death and dismemberment insurance and our 401(k) plan, in each case on the same basis as other employees, subject to applicable law. We also provide vacation and other paid holidays to all employees, including our named executive officers, which are comparable to those provided at peer companies.

During 2006, we owned and operated an airplane to facilitate the travel of senior executives in as safe a manner as possible and with the best use of their time. Messrs. Leach and Beal are entitled to utilize our aircraft for business travel and reasonable personal travel in North America. Certain other named executive officers use the corporate aircraft for business travel and, until May 13, 2006, used such aircraft for personal travel. The immediate family members of Messrs. Leach and Beal are also permitted to utilize our aircraft for their reasonable personal use in North America. Messrs. Leach and Beal are not obligated to reimburse us for the use of such aircraft except when their immediate family members use such aircraft without one of Messrs. Leach or Beal accompanying them on the flight, in which case they shall be obligated to reimburse us for the variable costs of such use. The amount of personal and family travel using our aircraft is subject to annual review and adjustment by the compensation committee.

The value of personal aircraft usage described above is based on our direct operating cost. This methodology calculates our incremental cost based on the average weighted cost of fuel, on-board catering, aircraft maintenance, landing fees, trip-related hangar and parking costs, and smaller variable costs. Since the corporate aircraft is used primarily for business travel, the methodology excludes fixed costs which do not change based on usage, such as pilots and other employees salaries, purchase costs of the aircraft and non-trip-related hangar expenses. On occasions when an executive s spouse or other family member accompanies the executive on a flight, no additional direct operating cost is incurred under the foregoing methodology.

Tax and accounting policies. We account for equity compensation paid to our employees under SFAS 123R, which requires us to estimate and record an expense over the service period of the award. Our cash compensation is recorded as an expense at the time the obligation is accrued. We receive a tax deduction for the compensation expense. We structure cash bonus compensation so that it is taxable to our executives at the time it becomes available to them. We currently intend that all cash compensation paid will be tax deductible for us. However, with respect to equity compensation awards, while any gain recognized by employees from nonqualified options granted at fair market value should be deductible, to the extent that an option constitutes an incentive stock option, gain recognized by the optionee will not be deductible if there is no disqualifying disposition by the optionee. In addition, if we grant restricted stock or restricted stock unit awards that are not subject to performance vesting, they may not be fully deductible by us at the time the award is otherwise taxable to employees.

Executive compensation tables

The following table presents compensation information for our fiscal year ended December 31, 2006 paid to or accrued for our chief executive officer, chief financial officer and each of our four other most highly compensated executive officers whose aggregate salary and bonus was more than $100,000. We refer to these executive officers as our named executive officers elsewhere in this prospectus.

Summary Compensation Table

Name and principal position	Salary(1)	Bonus	Option awards(2)	All other compensation(3)	Total
Timothy A. Leach *Chairman and Chief Executive Officer*	$ 333,333	$	$ 603,840	$ 34,124	$ 971,297
Steven L. Beal *President and Chief Operating Officer*	333,333		603,840	18,395	955,568
David W. Copeland *Vice President General Counsel and Secretary*	233,333		375,905	17,951	627,189
Curt F. Kamradt *Vice President, Chief Financial Officer and Treasurer*	233,333		375,905	13,883	623,121
E. Joseph Wright *Vice President Engineering and Operations*	233,333		375,905	14,055	623,293
David M. Thomas III *Vice President Exploration and Land*	233,333		324,649	15,753	573,735

(1) From January 1, 2006 until the completion of the combination transaction on February 27, 2006, our named executive officers received compensation as officers of Concho Equity Holdings Corp., our predecessor for accounting purposes. For their service as named executive officers of our company from February 28, 2006 through December 31, 2006, Messrs. Leach and Beal each earned $283,333 and Messrs. Copeland, Kamradt, Wright and Thomas each earned $200,000.

(2) The amounts in this column represent the dollar amount recognized for financial statement reporting purposes with respect to the fiscal year computed in accordance with SFAS No. 123R. Please see Note H of the notes to our consolidated financial statements for a discussion of all assumptions made in determining the grant date fair values. The stock option grants are comprised of grants on February 23, 2006 and June 12, 2006. Grants made on February 23, 2006 were made under the stock option plan dated August 13, 2004, as amended and restated as of February 27, 2006. Grants made on June 12, 2006 were made under the 2006 Stock Incentive Plan dated

June 1, 2006. Options granted February 23, 2006 vest at the end of three years commencing on the first anniversary of the date of grant. Options granted on June 12, 2006 vest as to 1/4 of the shares underlying the option on each of the first four anniversaries of the grant date. Option awards reported for Mr. Leach are comprised of $461,520 for options granted February 23, 2006 and $143,320 for options granted June 12, 2006. Options awards reported for Mr. Beal are comprised of $461,520 for options granted February 23, 2006 and $143,320 for options granted June 12, 2006. Options awards reported for Mr. Kamradt are comprised of $205,121 for options granted February 23, 2006 and $170,784 for options granted June 12, 2006. Options awards reported for Mr. Copeland are comprised of $205,121 for options granted February 23, 2006 and $170,784 for options granted June 12, 2006. Option awards reported for

Mr. Thomas are comprised of $96,938 for options granted February 23, 2006 and $227,711 for options granted June 12, 2006. Options awards reported for Mr. Wright are comprised of $205,121 for options granted February 23, 2006 and $170,784 for options granted June 12, 2006.

(3) All other compensation reported for Mr. Leach represents a $14,987 matching contribution by our company to our 401(k) Plan, of which $12,615 was for the period from February 28, 2006 through December 31, 2006; $55 for life insurance premiums, of which $46 was for the period from February 28, 2006 through December 31, 2006; and $19,082 for personal use of our company s airplane, of which $16,646 was for the period from February 28, 2006 through December 31, 2006. All other compensation reported for Mr. Beal represents a $14,998 matching contribution by our company to our 401(k) Plan, of which $12,616 was for the period from February 28, 2006 through December 31, 2006; $55 for life insurance premiums, of which $46 was for the period from February 28, 2006 through December 31, 2006; and $3,342 for personal use of our company s airplane, all of which was for the period from February 28, 2006 through December 31, 2006. All other compensation reported for Mr. Kamradt represents a $13,828 matching contribution by our company to our 401(k) Plan, of which $11,828 was for the period from February 28, 2006 through December 31, 2006 and $55 for life insurance premiums, of which $46 was for the period from February 28, 2006 through December 31, 2006. All other compensation reported for Mr. Copeland represents a $14,000 matching contribution by our company to our 401(k) Plan, of which $12,000 was for the period from February 28, 2006 through December 31, 2006; $55 for life insurance premiums, of which $46 was for the period from February 28, 2006 through December 31, 2006; and $3,896 for personal use of our company s airplane, of which $2,320 was for the period from February 28, 2006 through December 31, 2006. All other compensation reported for Mr. Thomas represents a $14,000 matching contribution by our company to our 401(k) Plan, of which $12,000 was for the period from February 28, 2006 through December 31, 2006; $55 for life insurance premiums, of which $46 was for the period from February 28, 2006 through December 31, 2006; and $1,698 for personal use of our company s airplane, all of which was for the period from February 28, 2006 through December 31, 2006. All other compensation reported for Mr. Wright represents a $14,000 matching contribution by our company to our 401(k) Plan, of which $12,000 was for the period from February 28, 2006 through December 31, 2006 and $55 for life insurance premiums, of which $46 was for the period from February 28, 2006 through December 31, 2006.

Grants of plan-based awards in last fiscal year

The following table provides information with regard to each stock option granted to each named executive officer during 2006.

Name	Grant date	Number of securities underlying options	Exercise price of option awards	Estimated fair market value of common stock on date of grant[3]	Grant date fair value of option awards
Timothy A. Leach	February 23, 2006	261,855(1)	$ 4.00(1)	$ 5.76	$ 568,896
	June 12, 2006	125,000(2)	6.00(2)	7.70	493,750
Steven L. Beal	February 23, 2006	261,855(1)	4.00(1)	5.76	568,896

	June 12, 2006	125,000(2)	6.00(2)	7.70	493,750
David W. Copeland	February 23, 2006	116,380(1)	4.00(1)	5.76	252,842
	June 12, 2006	150,000(2)	6.00(2)	7.70	592,500
Curt F. Kamradt	February 23, 2006	116,380(1)	4.00(1)	5.76	252,842
	June 12, 2006	150,000(2)	6.00(2)	7.70	592,500
E. Joseph Wright	February 23, 2006	116,380(1)	4.00(1)	5.76	252,842
	June 12, 2006	150,000(2)	6.00(2)	7.70	592,500
David M. Thomas III	February 23, 2006	55,000(1)	4.00(1)	5.76	119,491
	June 12, 2006	200,000(2)	6.00(2)	7.70	790,000

(1) On February 23, 2006, each of our named executive officers received a stock option grant as an executive officer of Concho Equity Holdings Corp., our predecessor for accounting purposes. Upon completion of the combination transaction, each outstanding option to purchase shares of Concho Equity Holdings Corp. was converted into an option to purchase 2.5 shares of our common stock at an exercise price of $4.00 per share. The number of securities underlying the option award is shown as converted to our common stock. For each of these options, 78% of the total award became vested and exercisable on February 27, 2006 and the remaining 22% will become exercisable on February 27, 2009.

(2) Each of these options become exercisable as to 1/4 of the shares underlying the option on each of the first four anniversaries of the grant date commencing June 12, 2007. These options also contain provisions that provide for accelerated vesting upon

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the occurrence of certain events following a change of control of our company, as discussed below in Employment, severance and change of control arrangements.

(3) The estimated fair market value of common stock on date of grant represents the per share dollar amount recognized for financial statement reporting purposes with respect to the fiscal year computed in accordance with SFAS No. 123R.

Outstanding option awards at December 31, 2006

The following table presents the outstanding option awards held as of December 31, 2006 by each named executive officer.

Name	Grant date	Number of securities underlying unexercised options(1) Exercisable	Unexercisable	Exercise price of option awards	Option expiration date
Timothy A. Leach	August 13, 2004	139,260(2)	39,278(2)(3)	$4.00(2)	August 13, 2014
	December 6, 2004	216,316(2)	61,012(2)(3)	4.00(2)	December 6, 2014
	July 15, 2005	92,839(2)	26,185(2)(3)	4.00(2)	June 15, 2015
	December 30, 2005	139,260(2)	39,278(2)(3)	4.00(2)	December 30, 2015
	February 23, 2006	204,247(2)	57,608(2)(3)	4.00(2)	February 23, 2016
	June 12, 2006		125,000(4)	6.00	June 12, 2016
Steven L. Beal	August 13, 2004	139,260(2)	39,278(2)(3)	$4.00(2)	August 13, 2014
	December 6, 2004	216,316(2)	61,012(2)(3)	4.00(2)	December 6, 2014
	July 15, 2005	92,839(2)	26,185(2)(3)	4.00(2)	July 15, 2015
	December 30, 2005	139,260(2)	39,278(2)(3)	4.00(2)	December 30, 2015
	February 23, 2006	204,247(2)	57,608(2)(3)	4.00(2)	February 23, 2016
	June 12, 2006		125,000(4)	6.00	June 12, 2016
David W. Copeland	August 13, 2004	61,893(2)	17,457(2)(3)	4.00(2)	August 13, 2014
	December 6, 2004	96,141(2)	27,117(2)(3)	4.00(2)	December 6, 2014
	July 15, 2005	41,261(2)	11,638(2)(3)	4.00(2)	July 15, 2015
	December 30, 2005	61,893(2)	17,457(2)(3)	4.00(2)	December 30, 2015
	February 23, 2006	90,776(2)	25,604(2)(3)	4.00(2)	February 23, 2016
	June 12, 2006		150,000(4)	6.00	June 12, 2016
Curt F. Kamradt		61,893(2)	17,457(2)(3)	4.00(2)	August 13, 2014

	August 13, 2004				
	December 6, 2004	96,141(2)	27,117(2)(3)	4.00(2)	December 6, 2014
	July 15, 2005	41,261(2)	11,638(2)(3)	4.00(2)	July 15, 2015
	December 30, 2005	61,893(2)	17,457(2)(3)	4.00(2)	December 30, 2015
	February 23, 2006	90,776(2)	25,604(2)(3)	4.00(2)	February 23, 2016
	June 12, 2006		150,000(4)	6.00	June 12, 2016
E. Joseph Wright	August 13, 2004	61,893(2)	17,457(2)(3)	4.00(2)	August 13, 2014
	December 6, 2004	96,141(2)	27,117(2)(3)	4.00(2)	December 6, 2014
	July 15, 2005	41,261(2)	11,638(2)(3)	4.00(2)	July 15, 2015
	December 30, 2005	61,893(2)	17,457(2)(3)	4.00(2)	December 30, 2015
	February 23, 2006	90,776(2)	25,604(2)(3)	4.00(2)	February 23, 2016
	June 12, 2006		150,000(4)	6.00	June 12, 2016
David M. Thomas III	April 15, 2005	74,685(2)	21,065(2)(3)	4.00(2)	April 15, 2015
	July 15, 2005	19,500(2)	5,500(2)(3)	4.00(2)	July 15, 2015
	December 30, 2005	29,250(2)	8,250(2)(3)	4.00(2)	December 30, 2015
	February 23, 2006	42,900(2)	12,100(2)(3)	4.00(2)	February 23, 2016
	June 12, 2006		200,000(4)	6.00	June 12, 2016

(1) These options contain provisions that provide for accelerated vesting upon the occurrence of certain events following a change of control of our company, as discussed below in Employment, severance and change of control arrangements.

(2) Prior to the completion of the combination transaction on February 27, 2006, Concho Equity Holdings Corp, our predecessor for accounting purposes, made awards of stock options to our named executive officers. Upon completion of the combination transaction, each outstanding option to purchase shares of Concho Equity Holdings Corp. was converted into an option

to purchase 2.5 shares of our common stock at an exercise price of $4.00 per share. The number of securities underlying the option award is shown as converted to our common stock.

(3) These options will vest on February 27, 2009.

(4) These options will vest in one-fourth increments on each anniversary of the grant date, commencing on June 12, 2007.

Option exercises in last fiscal year

No shares were acquired pursuant to the exercise of options by any named executive officer during 2006.

Employment, severance and change of control arrangements

We entered into employment agreements with all of our named executive officers, each with an effective date as of June 1, 2006. These employment agreements are substantially similar and have an initial term that expires three years from the effective date, but will automatically be extended for successive one-year terms after the initial term unless either party gives written notice within 90 days prior to the end of the term. Under these agreements, Mr. Leach and Mr. Beal s minimum annual base salaries are $350,000 and Messrs. Copeland, Kamradt, Wright and Thomas s minimum annual base salaries are $250,000. All of our named executive officers are eligible to receive cash bonuses as and when approved by our board of directors or compensation committee. Mr. Leach and Mr. Beal are entitled to utilize our aircraft for business use, and they and their families are entitled to use our aircraft for reasonable personal use and are not required to reimburse us for any cost related to such use unless a family member travels without either Mr. Leach or Mr. Beal.

If one of our named executive officer s employment is terminated by us without cause (and not by reason of his death or disability), or if he terminates his employment following a change in duties, then we will provide him with certain severance benefits. If such a termination of employment occurs prior to a change of control or more than two years after a change of control, then his base salary will continue to be paid for 12 months and we will reimburse him for up to 12 months for the amount by which the cost of his continued coverage under our group health plans exceeds the employee contribution amount that we charge our active senior executives for similar coverage. If such a termination of employment occurs during the two-year period beginning on the date upon which a change of control occurs (a change of control period), then he will be entitled to a lump sum severance amount equal to two times his annual base salary, all of his stock options and restricted stock awards will vest in full, and we will reimburse him for up to 18 months for the amount by which the cost of his continued coverage under our group health plans exceeds the employee contribution amount that we charge our active senior executives for similar coverage. If the total amount of payments to be provided by our company in connection with a change in control would cause any of the named executive officers to incur golden parachute excise tax liability, then the payments will be reduced to the extent necessary to leave him in a better after-tax position than if no such reduction had occurred. The agreement does not provide for any tax gross-up payments. We will have cause to terminate a named executive officer s employment if he (1) has engaged in gross negligence, gross incompetence or willful misconduct in the performance of his duties, (2) has materially breached any material provision of his employment agreement, corporate policy or code of conduct established by our company, (3) has willfully engaged in conduct that is materially injurious to our company, (4) has committed an act of fraud, embezzlement or willful breach of a fiduciary duty to our company, (5) has been convicted of a crime involving fraud, dishonesty or moral turpitude or any felony, or (6) has refused, without proper reason, to perform his duties. Prior to a change of control or after the expiration of a change of control period, a named executive officer will incur a change in

duties if there is a reduction in the rank of his title as an officer of our company, a reduction in his base salary, or a material diminution in his employee benefits and perquisites from those substantially similar to those provided to similarly situated executives. During a change of control period, a named executive officer will incur a change in duties if there is (a) a material reduction in the nature or scope of his authorities or duties, (b) a reduction in his base salary, (c) a diminution in his eligibility to participate in bonus, stock option, incentive award and other compensation plans, (d) a material diminution in his employee benefits and perquisites, or (e) a change in the location of his principal place of employment by more than 10 miles. In addition, each of the employment agreements contains provisions that prohibit, with certain limitations, the named executive officer from competing with us; soliciting any of our customers, vendors, or acquisition candidates; or soliciting or hiring any of our employees or inducing any of them to terminate their employment with us. These restrictions will generally continue for a period of 12 months following termination of employment, except under certain circumstances we must agree to continue to pay the named executive officer s base salary in order for the non-competition restrictions to continue to apply.

In addition to the acceleration of vesting provisions described above, all options to purchase common stock issued to our named executive officers may be subject to accelerated vesting upon a change of control as described below in the section entitled Potential payments upon change of control under employment agreements.

Potential payments upon change of control under employment agreements

The following table summarizes the potential payments to each named executive officer assuming that one of the events described in the table below occurs. The table assumes that the event occurred on December 31, 2006. We have assumed a price per share of our common stock of $.

	Termination of employment by our company without cause (and not by reason of death or disability) or resignation following a change in duties	
Name	**Prior to, or more than two years after a change of control**	**Within two years after a change of control**
Timothy A. Leach	(1)	(2)
Steven L. Beal	(1)	(2)
David W. Copeland	(3)	(4)
Curt F. Kamradt	(3)	(4)
E. Joseph Wright	(3)	(4)
David M. Thomas III	(3)	(4)

(1) Includes payment of $350,000 for the continuation of salary and $18,173 for continuation of health benefits for a period of 12 months following such termination.

(2) Includes payment of $700,000 in a lump sum payment for salary, $27,259 for continuation of health benefits for a period of 18 months following such termination and $ for accelerated vesting of equity awards, based on the fair value of unvested stock options as of December 31, 2006 in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 123R, Share-based Payment.

(3) Includes payment of $250,000 for the continuation of salary and $18,173 for continuation of health benefits for a period of 12 months following such termination.

(4) Includes payment of $500,000 in a lump sum payment for salary, $27,259 for continuation of health benefits for a period of 18 months following such termination and $ for accelerated vesting of equity awards for Messrs. Copeland, Kamradt and Wright and $ for accelerated vesting of equity awards for Mr. Thomas, based on the fair value of unvested stock options as of December 31, 2006 in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 123R, Share-based Payment.

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Director compensation

Directors who are not employees of our company, which we refer to as Outside Directors, receive compensation for serving on our board of directors. Our objectives for director compensation are to remain competitive with the compensation paid to directors of comparable companies while adhering to corporate governance best practices with respect to such compensation, and to reinforce our practice of encouraging stock ownership. Our Outside Director compensation includes:

- an annual retainer of $35,000;
- a meeting attendance fee of $1,000 for each board meeting attended;
- a committee meeting attendance fee of $500 for each board committee meeting attended; and
- on an annual basis, commencing with the second year of service, an award of 5,000 shares of restricted stock under our company s equity compensation plan.

On June 1, 2006, the board of directors approved a one-time award to the Outside Directors of 10,000 shares of restricted stock under our 2006 Stock Incentive Plan, which shares fully vested on January 2, 2007. All directors are reimbursed for all reasonable out-of-pocket expenses incurred in attending meetings of the board of directors and committees thereof. The following table presents compensation information for our fiscal year ended December 31, 2006 paid to or accrued for our directors.

Director compensation

Name(1)	Fees	Stock Awards(2)	Total
Tucker S. Bridwell	$ 17,166	$ 77,000	$ 94,166
W. Howard Keenan, Jr.(3)	15,666	77,000	92,666
A. Wellford Tabor(4)	17,166	77,000	94,166
G. Carl Everett(5)	17,666	77,000	94,666
Larry V. Kalas(5)	16,666	77,000	93,666
John A. Knorr(5)	13,666	77,000	90,666
Bradley D. Bartek(5)	14,666	77,000	91,666
Robert C. Chase(5)	13,666	77,000	90,666

(1) Our employee directors have been omitted from this table because they receive no compensation for serving on our board of directors.

(2) The grant date fair value of the equity award computed in accordance with FAS 123R for each director reflected in the column below was $77,000. As of December 31, 2006, each director held 10,000 restricted stock awards in the aggregate and no option awards.

(3) Mr. Keenan remits all fees received as director compensation to Yorktown Energy Partners V, L.P. and Yorktown Energy Partners VI, L.P. and holds all securities received as director compensation for the benefit of those entities. Mr. Keenan disclaims beneficial ownership of all such securities as well as those held by those

entities, except to the extent of his pecuniary interest therein.

(4) Mr. Tabor remits all fees received as director compensation to Wachovia Capital Partners (WCP) and holds all securities received as director compensation for the benefit of WCP. Mr. Tabor disclaims beneficial ownership of all such securities as well as those held by WCP and its affiliates, except to the extent of his pecuniary interest therein.

(5) Messrs. Everett, Kalas, Knorr, Bartek and Chase each resigned as a director on April 23, 2007.

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2006 Stock Incentive Plan

The following contains a summary of the material terms of our 2006 Stock Incentive Plan, which was adopted by our board of directors and approved by our stockholders. The description of the Stock Incentive Plan does not describe all aspects of the plan. For more information, we refer you to the full text of the Stock Incentive Plan, which has been filed as an exhibit to the registration statement of which this prospectus is a part.

The 2006 Stock Incentive Plan permits the grant of non-qualified stock options, incentive stock options, stock appreciation rights issued in tandem with stock options or phantom stock awards, restricted stock, phantom stock, performance awards and other stock-based awards to our employees, directors and consultants and to employees and consultants of our affiliates, provided that incentive stock options may be granted solely to employees. A maximum of 11,700,000 shares of common stock may be delivered pursuant to awards under the 2006 Stock Incentive Plan. The number of shares deliverable pursuant to awards under the 2006 Stock Incentive Plan is subject to adjustment as a result of mergers, consolidations, reorganizations, stock splits, stock dividends and other similar changes in our common stock. Shares of common stock used to pay exercise prices and to satisfy tax withholding obligations with respect to awards as well as shares covered by awards that expire, terminate or lapse will again be available for awards under the 2006 Stock Incentive Plan.

Administration. The 2006 Stock Incentive Plan is administered by the compensation committee of the board of directors. Our compensation committee has the sole discretion to determine the employees, directors and consultants to whom awards may be granted under the 2006 Stock Incentive Plan and the manner in which such awards will vest. The compensation committee is authorized to construe the 2006 Stock Incentive Plan, to prescribe rules and regulations relating to the 2006 Stock Incentive Plan, and to make any other determinations that it deems necessary or advisable for administering the 2006 Stock Incentive Plan. Our compensation committee may correct any defect, supply any omission or reconcile any inconsistency in the 2006 Stock Incentive Plan in the manner and to the extent the compensation committee deems expedient to carry the 2006 Stock Incentive Plan into effect.

Stock Options. Our compensation committee will determine the exercise price for each stock option award. Options must have an exercise price at least equal to the fair market value of the common stock on the date the option is granted. An option holder may exercise an option by written notice and payment of the exercise price:

in cash;

if the option agreement so provides, by a cashless exercise, in accordance with procedures approved by the compensation committee; or

if the option agreement so provides, by delivery of a number of shares of common stock (plus cash if necessary) having a fair market value equal to the option price.

Stock Appreciation Rights. A stock appreciation right permits the holder to receive an amount (in cash, common stock, or a combination thereof) equal to the number of stock appreciation rights exercised by the holder, multiplied by the excess of the fair market value of common stock on the exercise date over the stock appreciation rights exercise price. Stock appreciation rights may be granted in connection with the grant of an option or a phantom stock award. The exercise price of stock appreciation rights granted under the 2006 Stock Incentive Plan will be determined by the compensation committee; provided, however, that such exercise price cannot be less than the fair market value of a share of common stock on a date the stock appreciation right is granted (subject to adjustments). A stock appreciation right may be exercised in whole or in such installments and at such times as determined by the compensation committee.

Restricted Stock Awards. Pursuant to a restricted stock award, shares of common stock may be granted at any time the award is made with or without any cash payment to us, as determined by the compensation committee; provided, however, that such shares will be subject to certain restrictions on the disposition thereof and certain obligations to forfeit such shares to us as may be determined in the discretion of the compensation committee. The compensation committee may provide that the restrictions on disposition may lapse based upon (a) the attainment of specific performance measures established by the compensation committee; (b) the participant s continued service with us; (c) the occurrence of any other event or condition specified by the compensation committee in its sole discretion; or (d) a combination of any of the foregoing factors. A participant may not sell, transfer, pledge, exchange, hypothecate, or otherwise dispose of such shares until the expiration of the restriction period.

Transferability. Unless otherwise determined by our compensation committee, awards granted under the 2006 Stock Incentive Plan are not transferable other than by will or by the laws of descent and distribution or, in some cases, pursuant to the terms of a qualified domestic relations order. Incentive stock options may be exercisable during the participant s lifetime only by such participant or his legal representative or guardian.

Change of Control. In the event of a Corporate Change (as defined in the 2006 Stock Incentive Plan), the compensation committee may provide for:

the substitution of similar options with respect to the stock of the successor company;

the acceleration of the vesting of all or any portion of certain awards; or

the mandatory surrender to us by selected participants of some or all of the outstanding awards held by such participants, at which time we will cancel such awards and cause to be paid to each affected participant a certain amount of cash per share, as specified in the 2006 Stock Incentive Plan.

Amendment and Termination. Our board of directors in its discretion may terminate the 2006 Stock Incentive Plan at any time with respect to any shares of common stock for which awards have not been granted. Our board of directors may alter or amend the 2006 Stock Incentive Plan from time to time, except that no change may be made that would impair the rights of a participant with respect to an outstanding award without the consent of the participant. In addition, our board of directors may not, without approval of our stockholders:

amend the 2006 Stock Incentive Plan to increase the maximum aggregate number of shares that may be issued under the 2006 Stock Incentive Plan; or

increase the maximum number of shares that may be issued under the 2006 Stock Incentive Plan through incentive stock options or change the class of individuals eligible to receive awards under the 2006 Stock Incentive Plan.

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Indemnification of directors and executive officers and limitation of liability

We have also entered into indemnification agreements with each of our executive officers and directors. These indemnification agreements are intended to permit indemnification to the fullest extent now or hereafter permitted by the General Corporation Law of the State of Delaware. It is possible that the applicable law could change the degree to which indemnification is expressly permitted.

The indemnification agreements cover expenses (including attorneys fees), judgments, fines and amounts paid in settlement incurred as a result of the fact that such person, in his or her capacity as a director or officer, is made, threatened or reasonably expected to be made a party to any suit or proceeding. The indemnification agreements generally cover claims relating to the fact that the indemnified party is or was an officer, director, employee or agent of us or any of our subsidiaries, or is or was serving at our request in such a position for another entity. The indemnification agreements also obligate us to promptly advance all expenses incurred in connection with any claim. The indemnitee is, in turn, obligated to reimburse us for all amounts so advanced if it is later determined that the indemnitee is not entitled to indemnification. The indemnification provided under the indemnification agreements is not exclusive of any other indemnity rights; however, double payment to the indemnitee is prohibited.

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Principal and selling stockholders

The following table sets forth certain information regarding the beneficial ownership of our common stock prior to and as of the closing of this offering by:

- each person who will beneficially own more than 5% of our common stock then outstanding;
- each of our named executive officers;
- each of our directors;
- all of our directors and executive officers as a group; and
- each selling stockholder.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or stockholders, as the case may be. The number of shares in the column Number of shares offered represents all of the shares that each selling stockholder may offer under this prospectus assuming no exercise of the underwriters over-allotment option. Except as noted below in the footnotes, Chase Oil Corporation, Caza Energy LLC, Richard L. Chase, Robert C. Chase and Gerene Dianne Chase Ferguson will each sell a pro rata number of the total shares that may be sold pursuant to the underwriters over-allotment option. To our knowledge, upon the completion of this offering, each of the persons named below will have sole voting and investment power as to the shares shown, except as disclosed in this prospectus or to the extent this power may be shared with a spouse. None of the selling stockholders are broker dealers or affiliates of broker dealers. Beneficial ownership as shown in the table below has been determined in accordance with the applicable rules and regulations promulgated under the Securities Exchange Act of 1934.

	Shares beneficially owned prior to the offering		Number of shares	Shares beneficially owned after this offering[1][2]	
Name of beneficial owner	**Number**	**% of class**	**offered**	**Number**	**% of class**
Chase Oil Corporation[3]	56,009,965				
Caza Energy LLC[4][6][8]	4,999,851				
Richard L. Chase[5]	2,504,914				
Robert C. Chase[6]	9,017,741				
Gerene Dianne Chase Ferguson[7]	1,849,007				
Mack C. Chase[8]	4,999,851				
Yorktown Energy Partners V, L.P.[9]	6,330,000				
Yorktown Energy Partners VI, L.P.[9]	14,995,000				
Yale University[10]	6,397,500				
Timothy A. Leach[11][17]	2,870,944				
Steven L. Beal[11][17]	2,870,945				
David W. Copeland[11][17]	1,299,589				
Curt F. Kamradt[11][17]	1,299,589				
David M. Thomas III[11][17]	642,835				

E. Joseph Wright[11][17]	1,299,589
Tucker S. Bridwell[12][17]	1,454,438

Name of beneficial owner	Shares beneficially owned prior to the offering Number	% of class	Number of shares offered	Shares beneficially owned after this offering[1][2] Number	% of class
W. Howard Keenan, Jr.[13][17]	21,340,000				
A. Wellford Tabor[14][17]	15,000				
Buckhorn Enterprises Corp.[15]	62,770				
Russell Hall	63,976				
Calvin J. Serpas	85,300				
James Caupto	106,626				
The Merle Lloyd Ericson and Rebecca Sue Ericson Revocable Trust Dated 04/23/96[16]	7,246				
Steve Guthrie	185,528				
Greg Wilkes	106,625				
Stephen L. and Shelly L. George	36,337				
Amy M. Penland	63,978				
Charles E. and Gloria J. Sadler	11,519				
Matt J. and Kellie R. Brewer	34,280				
Mark T. Brewer	59,000				
John A. Knorr	15,000				
Bradley D. and Melissa J. Bartek	27,466				
Johnny M. and Beverly J. King	20,928				
Luis and Carrie Hernandez	5,393				
Henry A. and Loretta J. Hall	29,461				
Crissa D. and Rodney D. Carter	16,666				
J. Robert Ready	85,300				
Gayle Burleson	66,108				
Brent Robertson	85,300				
Ryan Simpson	42,651				
Renee Runkel	89,565				
Ramon G. Reyes	85,300				
Gary B. Mackay	170,600				
Charlotte L. and Warren D. Gleghorn	25,000				
Jay S. May	85,300				
Keith R. Corbett	63,977				
All directors and executive officers as a group (10 persons)[11][17]	33,092,929				

* Less than 1%.

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(1) Assumes no exercise of the underwriters over-allotment option to purchase an aggregate of shares, granted by . If such over-allotment option is exercised in full, will beneficially own shares (%) after the offering.

(2) Based upon an aggregate of shares to be outstanding following the completion of this offering.

(3) The address of Chase Oil Corporation is P.O. Box 1767, Artesia, NM 88211-1767. The directors of Chase Oil Corporation are Mack C. Chase, Robert C. Chase and Rebecca S. Ericson.

(4) The address of Caza Energy LLC is P.O. Box 1767, Artesia, NM 88211-1767. The managers of Caza Energy LLC are Mack C. Chase and Robert C. Chase.

(5) The address of Richard Chase is P.O. Box 359, Artesia, NM 88211-0359.

(6) Robert C. Chase directly owns 4,017,890 shares of common stock. Robert C. Chase is the beneficial owner of the shares owned by Caza Energy LLC, of which Robert C. Chase is a Manager and therefore shares voting and investment power with respect to the shares owned by Caza Energy LLC. Robert C. Chase disclaims beneficial ownership in the shares held by Caza Energy LLC except to the extent of his pecuniary interest in Caza Energy LLC. The address of Robert C. Chase is P.O. Box 297, Artesia, NM 88211-0297.

(7) The address of Ms. Ferguson is P.O. Box 693, Artesia, NM 88211-0693.

(8) Mack C. Chase is the beneficial owner of the shares owned by Caza Energy LLC, of which Mack C. Chase is a Manager and therefore shares voting and investment power with respect to the shares owned by Caza Energy LLC. Mack C. Chase disclaims beneficial ownership in the shares held by Caza Energy LLC except to the extent of his pecuniary interest in Caza Energy LLC. The address of Mack C. Chase is P.O. Box 693, Artesia, NM 88211-0693.

(9) The address of Yorktown Energy Partners V, L.P. and Yorktown Energy Partners VI, L.P. is 410 Park Avenue, 19th Floor, New York, NY 10022.

(10) The address of Yale University Investments Office is 55 Whitney Ave, 5th floor, New Haven, CT 06510.

(11) The number of shares beneficially owned includes the following shares that are subject to options that are currently exercisable or will become exercisable within 60 days of the date of this prospectus:

Name of beneficial owner	Shares subject to options
Timothy A. Leach	823,172
Steven L. Beal	823,172
David W. Copeland	389,464
Curt F. Kamradt	389,464
David M. Thomas III	216,335
E. Joseph Wright	389,464