CRIMSON EXPLORATION INC.
Form S-1
November 20, 2009

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As filed with the Securities and Exchange Commission on November 20, 2009
Registration No. 333-

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

Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

CRIMSON EXPLORATION INC.
(Exact name of registrant as specified in its charter)

Delaware	**1311**	**20-3037840**
(State or other jurisdiction of Incorporation)	*(Primary Industrial Classification Code Number)*	*(I.R.S. Employer Identification No.)*

E. Joseph Grady
Senior Vice President and Chief Financial Officer
717 Texas Avenue, Suite 2900
Houston, Texas 77002
(713) 236-7400
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices and agent for service)

Copies to:

J. Michael Chambers
Patrick J. Hurley
Akin Gump Strauss Hauer & Feld LLP
1111 Louisiana Street, Suite 4400
Houston, Texas 77002
(713) 220-5800
(713) 236-0822 (fax)

James M. Prince
Gillian A. Hobson
Vinson & Elkins L.L.P.
1001 Fannin Street, Suite 2500
Houston, Texas 77002
(713) 758-2222
(713) 758-2346 (fax)

Approximate date of commencement of proposed sale to the public: As soon as practical 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, please 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

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

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

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Proposed Maximum Aggregate Offering Price[(1)(2)]	Amount of Registration Fee
Common Stock, $0.001 par value[(2)]	$100,000,000	$5,580

(1) Estimated solely for the purpose of calculating the amount of the registration fee pursuant to Rule 457(o) under the Securities Act of 1933, as amended.

(2) Includes shares of common stock subject to the underwriters   option to purchase additional shares.

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 or until this 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. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell nor does it seek an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion, dated November 20, 2009

PROSPECTUS

Shares

Common Stock

We are offering shares of our common stock. We intend to list our common stock on The NASDAQ Global Market. We anticipate that the initial public offering price per share of common stock will be between $ and $. Our common stock is currently traded on the Over-the-Counter Bulletin Board under the symbol CXPO.OB.

Investing in our common stock involves risks. See Risk Factors beginning on page 15.

	Per Share	Total
Price to the public	$	$
Underwriting discounts and commissions	$	$
Proceeds to us (before expenses)	$	$

We have granted the underwriters a 30-day option to purchase up to an additional shares from us on the same terms and conditions as set forth above if the underwriters sell more than shares of common stock in this offering.

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.

Barclays Capital, on behalf of the underwriters, expects to deliver the shares on or about , 2009.

Barclays Capital

Prospectus dated , 2009

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ABOUT THIS PROSPECTUS

You should rely only on the information contained in this document or to which we have referred you. We have not authorized anyone to provide you with information that is different. This document may only be used where it is legal to sell these securities. The information in this document may only be accurate on the date of this document.

Except as otherwise indicated herein or as the context otherwise requires, references in this prospectus to Crimson Exploration, Crimson, the Company, our company, we, our, and us refer collectively to Crimson Exploratio predecessor GulfWest Energy Inc. and our subsidiaries.

Our natural gas and crude oil reserve information as of December 31, 2008 included in this prospectus is based on a reserve report prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineering firm. A summary of that report is attached as Appendix B.

Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their option to purchase additional shares from us.

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PROSPECTUS SUMMARY

This summary highlights information appearing elsewhere in this prospectus. Because this is a summary, it may not contain all of the information that you should consider before investing in our common stock. You should carefully read the entire prospectus, including the financial data and related notes and the information presented under the caption Risk Factors, before making an investment decision. Certain terms used in this prospectus are defined in the Glossary of Selected Terms beginning on page A-1.

Our Company

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and early 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009. This well targeted the Haynesville Shale and initially produced 30.7 MMcfe/d, which we believe to be the highest publicly announced initial production rate to date in that formation. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Bossier Shale and James Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 net acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009, and we are preparing to complete the well in the Eagle Ford Shale.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of over 800 drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2008, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 131.9 Bcfe, consisting of 96.2 Bcf of natural gas and 6.0 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2008, 73% of our proved reserves were natural gas, 69% were proved developed and 81% were attributed to wells and properties operated by us. From 2006 to 2008, we grew our estimated proved reserves from 46.4 Bcfe to 131.9 Bcfe. In addition, we grew our average daily production from 7.3 MMcfe/d for the year ended December 31, 2006 to 43.0 MMcfe/d for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, we generated $55.2 million of Adjusted EBITDAX. Our definition of the non-GAAP financial measure of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX are provided under Non-GAAP Financial Measures and Reconciliations. For the same period, our net income (loss) was $(16.8) million.

After application of net proceeds of $ from this offering (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus), we expect to have approximately $ million of available borrowing capacity under our revolving credit facility to pursue our 2010 drilling program. Our 2010 capital budget is approximately $55 million, exclusive of acquisitions, of which we expect to spend approximately 76% of our budget on our East Texas and South Texas resource plays and 24% on our existing producing assets. We plan to drill 12 gross

(6.0 net) wells in 2010, including 7 gross (3.0 net) wells on our East Texas resource play acreage, one gross (0.4 net) well on our South Texas resource play acreage, and 4 gross (2.6 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, commodity prices, availability of capital and drilling and production results.

Our Strategy

The key elements of our business strategy are:

Develop our East Texas resource play. We have approximately 12,000 net acres in San Augustine and Sabine Counties of East Texas, which we believe is prospective in the Haynesville Shale, Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H. The well tested at 30.7 MMcfe/d, which we believe to be the highest publicly reported 24-hour initial production rate for a Haynesville Shale well in Texas or Louisiana to date and is currently flowing to sales. We believe the Kardell #1H confirms the potential of our Bruin Prospect, which is comprised of 3,000 net acres in San Augustine County, resulting in over 100 potential drilling locations in multiple formations. We are currently in the planning stages of several wells in this area and intend to further evaluate and exploit these multiple formations beginning in early 2010. We have an additional 9,000 net acres outside this prospect within Sabine and San Augustine Counties, and we expect to drill our initial well on that acreage in early 2010. We intend to allocate a substantial portion of our capital budget over the next several years to develop the significant potential that we believe exists on our East Texas acreage. Based on our current capital budget, we expect to drill approximately 7 gross (3.0 net) wells in 2010 that will target the Haynesville and Bossier Shales, while retaining future development opportunities in shallower formations.

Develop our South Texas resource play. We have approximately 2,800 net acres in Bee County, Texas which we believe is prospective in the Austin Chalk and Eagle Ford Shale. In November 2009, we drilled our initial well on this acreage, the Dubose #1. This well is in the process of being completed with results expected prior to year end 2009. We intend to allocate a portion of our capital budget in 2010 to validate the potential we believe exists on our acreage.

Exploit our existing producing property base to generate cash flows. We believe our multi-year drilling inventory of high return exploitation opportunities on our existing producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a larger portion of our resource plays and exploration activities from cash flows from operations. In 2010, we intend to focus much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which industry players have recently experienced success on wells in the area. We own 3D seismic data that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. We have drilled 11 gross (6.8 net) wells in Liberty County since early 2008 and have successfully completed 82%. During 2010, we intend to drill 4 gross (2.6 net) wells in this area.

Explore in defined producing trends. Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

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Make opportunistic acquisitions that meet our strategic and financial objectives. We seek to acquire natural gas and crude oil properties, including both undeveloped and producing reserves in areas where we have specific operating expertise.

Reduce commodity exposure through hedging. We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. As of September 30, 2009, we had 13.9 Bcfe of equivalent production hedged, representing 1.8 Bcf, 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 86 MBbl, 250 MBbl and 124 MBbl of crude oil hedges in place for the fourth quarter of 2009, the year 2010 and the year 2011, respectively. The average price of our natural gas and crude oil hedges in place is $8.19/MMBtu and $86.03/Bbl for the fourth quarter of 2009, $7.71/MMBtu and $83.02/Bbl in the year 2010 and $7.32/MMBtu and $66.50/Bbl in the year 2011.

Our Competitive Strengths

Our competitive strengths include:

Geographically focused operations in basins with established production profiles. The geographic concentration of our current operations along the onshore Texas Gulf Coast and in South Texas allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, and enables us to leverage our base of technical expertise in these geographic areas. In addition, we believe the cash flows from our existing properties provide a stable foundation to support our ongoing exploitation and development efforts.

Significant operational control. As of September 30, 2009, we operated a majority of our producing wells. As a result, we exercise a significant level of control over the amount and timing of expenses, capital allocation and other aspects of development, exploitation and exploration. While operatorship of future wells on our East Texas acreage will be subject to negotiation as drilling units are formed, we expect to operate a significant number of the wells we drill on this acreage.

Proven track record of reserve and production growth. Since 2005, we have significantly grown proved reserves and production through a combination of continued drilling success and the successful acquisition of underdeveloped properties that have proven to be complementary to our existing asset base and technical expertise. We plan to continue this growth by focusing on a balanced combination of drilling longer life, multi-pay natural gas targets within our resource plays and exploitation of our producing properties and undeveloped acreage.

Large inventory of identified projects. We currently have an inventory of over 800 identified potential drilling locations, including 375 associated with our existing conventional properties, plus an estimated 422 locations on our East Texas resource play acreage and an estimated 25 locations on our South Texas resource play acreage. Since the beginning of 2008, we have drilled 16 gross (10.7 net) operated and 18 gross (4.5 net) non-operated wells and have experienced a 91% success rate (excluding one well which has not yet been completed). We expect to drill 12 gross (6.0 net) wells in 2010.

Experienced management and technical teams. Our senior management team averages over 25 years of experience in the energy industry and is led by Allan D. Keel, President and Chief Executive Officer, who has 25 years of experience in the oil and natural gas industry. Mr. E. Joseph Grady, our Senior Vice President and Chief Financial Officer, has over 30 years of financial management experience in the energy industry. Other members of our senior management include: Mr. Tracy Price, our Senior Vice President Land Business/Development; Mr. Thomas H. Atkins, our Senior Vice President Exploration; and

Mr. Jay S. Mengle, our Senior Vice President Engineering, each of whom has more than 25 years of

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experience in the oil and gas industry. Our experienced management team has an established track record of successfully exploiting and developing natural gas and crude oil properties.

Our Operations

Our areas of primary focus include the following:

East Texas. Our East Texas properties include approximately 17,000 gross (12,000 net) acres acquired in 2008 and early 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, where we will focus primarily on the pursuit of the Haynesville Shale, Bossier Shale and James Lime formations. In October 2009, we drilled and completed our first well in this area, the Kardell #1H. While drilling this well, we identified additional prospective formations, including the Pettet and Knowles Lime.

Southeast Texas. Our Southeast Texas properties primarily include the Felicia field area in Liberty County. We own approximately 27,300 gross (15,100 net) acres in Liberty, Madison and Grimes Counties. As of September 30, 2009, we owned and operated 35 gross (27.0 net) producing wells, representing approximately 38% of our average daily production for the first nine months of 2009.

South Texas. Our South Texas properties include approximately 2,800 gross (2,800 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and Eagle Ford Shale. Our conventional operations include approximately 87,600 gross (50,700 net) acres predominately in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties.

We also own interests in the following areas:

Southwest Louisiana. Our Southwest Louisiana properties include approximately 8,200 gross (3,600 net) acres, primarily in the Fenton field area of Calcasieu Parish and our legacy Grand Lake and Lacassine fields in Cameron Parish. In addition, we own a 15% working interest ownership in 2007 exploratory successes in Louisiana at Sabine Lake and West Cameron 432.

Colorado and Other. Our Colorado and other properties include primarily producing assets and approximately 16,900 gross (11,900 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams County) and a minor crude oil property in Mississippi.

The following table sets forth certain information with respect to our estimated proved reserves as of December 31, 2008, as estimated by Netherland, Sewell & Associates, Inc., and production for the nine months ended September 30, 2009. The following table also identifies potential drilling locations and net acreage as of September 30, 2009.

Region	Estimated Proved Reserves as of December 31, 2008 (MMcfe)	% Natural Gas	% Proved Developed	Average Daily Production For the Nine Months Ended September 30, 2009 (Mcfe/d)	Net Acreage at September 30, 2009	Identified Potential Gross Drilling Locations at September 30, 2009[1]
Southeast Texas	29,393	60.1%	85.8%	16,521	15,100	26
South Texas	60,602	78.0%	59.8%	11,963	53,500	124
Southwest Louisiana	10,398	62.4%	57.3%	3,139	3,600	4
Colorado and Other	6,675	71.5%	55.3%	539	11,900	164
East Texas[2]					12,000	422
Non-operated[3]	24,879	80.2%	79.8%	10,817		82
Total	131,947	72.9%	68.9%	42,979	96,100	822

(1) Includes multiple drilling locations on acreage with multiple target formations.

(2) We recently completed our first well on our East Texas acreage, the Kardell #1H, as a horizontal Haynesville Shale producer, in which we own a 52% working interest. Drilling locations in this region were identified assuming an allocated 100 acres per potential horizontal East Texas well drilled to multiple target formations.

(3) Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% and 15% respective working interests resulting from exploratory successes in 2007 at Sabine Lake and West Cameron 432 in Southwest Louisiana.

Preferred Stock Conversion

As of September 30, 2009, there were 80,500 shares of our Series G convertible preferred stock, par value $0.01 per share (Series G Preferred Stock) outstanding. OCM GW Holdings, LLC (Oaktree Holdings), an affiliate of Oaktree Capital Management, LP (Oaktree Capital Management), currently holds 76,710 shares of our Series G Preferred Stock and Allan D. Keel, our President and CEO, holds 500 shares of our Series G Preferred Stock. Pursuant to a shareholders agreement among holders of the Series G Preferred Stock, if Oaktree Holdings elects to convert any shares of Series G Preferred Stock into common stock, all other holders must likewise convert a proportional number of shares. We expect to enter into an agreement with Oaktree Holdings that will provide us the right, in connection with this offering, to cause Oaktree Holdings to convert all of its shares of our Series G Preferred Stock and the accrued but unpaid dividends with respect to those preferred shares. We expect that the number of shares of our common stock to be issued per share of preferred stock will be equal to (i) the sum of $500 plus the accrued but unpaid dividends with respect to such share divided by (ii) the lesser of $9.00 and the price to the public for our common stock received in this offering. We intend to exercise this option and anticipate issuing shares of our common stock in connection with the conversion of all of our Series G Preferred Stock and the accrued but unpaid dividends on those shares, assuming an offering price of $ per share, which is the midpoint in the range provided on the cover page of this prospectus. Of those shares of common stock, we anticipate issuing shares of our common stock to Oaktree Holdings and shares of our common stock to Mr. Keel.

As of September 30, 2009, there were 2,100 shares of our Series H convertible preferred stock, par value $.01 per share (our Series H Preferred Stock) outstanding, which shares were held of record by three stockholders, including 2,000 shares held by Oaktree Holdings. Each share of our

Series H Preferred Stock is convertible into the number of shares of our common stock that is equal to $500 divided by $3.50. Pursuant to the Certificate of Designations governing the terms of the Series H Preferred Stock, if Oaktree Holdings converts all of its shares of Series G Preferred Stock into common stock, all other shares of Series H Preferred Stock automatically convert into shares of our common stock. We anticipate issuing shares of our common stock in connection with the conversion of all of our Series H Preferred Stock.

Upon the completion of this offering, Oaktree Holdings will own approximately % of our outstanding common stock and Mr. Keel will hold approximately % of our outstanding common stock. Please see Summary Consolidated Financial Data Pro Forma Net Income (Loss) Per Share Data for information with respect to the effect of the Preferred Stock Conversion on our net income (loss) per share.

Principal Stockholder

Our principal stockholder is Oaktree Holdings, an affiliate of Oaktree Capital Management. Oaktree Capital Management is a premier global alternative and non-traditional investment manager with over $67 billion in assets under management as of September 30, 2009. The firm emphasizes an opportunistic, value-oriented and risk-controlled approach to investments in distressed debt, high yield and convertible bonds, specialized private equity (including power infrastructure), real estate, emerging market and Japanese securities, and mezzanine finance. Oaktree Capital Management was founded in 1995 by a group of principals who have worked together since the mid-1980s. Headquartered in Los Angeles, the firm today has over 580 employees in 14 offices worldwide.

Risk Factors

Investing in our common stock involves substantial risk. For a discussion of certain risks you should consider in making an investment, see Risk Factors beginning on page 15. 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:

- Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.

- Initial production rates in the Haynesville Shale tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

- Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids 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 quantities and present value of our reserves.

- We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

- Unless we replace our natural gas and crude oil 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.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

Corporate Structure

Our company was founded in 1987 and is incorporated in Delaware. In February 2005, the Company, previously incorporated in Texas and named GulfWest Energy Inc., was recapitalized and in June 2005 was reincorporated as a Delaware corporation, and renamed Crimson Exploration Inc. We are organized as a holding company with most of our oil and gas assets held in our primary operating subsidiary.

Our Offices

Our principal office is located at 717 Texas Avenue, Suite 2900, Houston, Texas 77002 and our telephone number is (713) 236-7400.

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The Offering

Issuer	Crimson Exploration Inc.
Common stock offered by us	shares
Underwriters option to purchase additional shares	We have granted the underwriters a 30-day option to purchase up to an additional shares of common stock.
Common stock outstanding immediately following this offering	shares of common stock (excluding shares that will be sold to the underwriters if they exercise their option to purchase additional shares), including shares that will be issued pursuant to the Preferred Stock Conversion, assuming an offering price of $, which is the midpoint of the range provided on the cover page of this prospectus
Use of proceeds	We estimate that our net proceeds from this offering will be approximately $ million after deducting underwriting discounts and commissions and estimated offering expenses, assuming an offering price of $, which is the midpoint of the range provided on the cover page of this prospectus. We intend to use the net proceeds from this offering to repay approximately $ in aggregate principal amount of indebtedness outstanding under our revolving credit facility and our $10 million unsecured promissory note.
Dividend policy	We have not declared or paid any cash dividends on our common stock or preferred stock, and we do not currently anticipate paying any cash dividends on our common stock or preferred stock in the foreseeable future. For more information, see Dividend Policy.
Proposed NASDAQ symbol	CXPO
Risk factors	An investment in our common stock involves a high degree of risk. See Risk Factors and other information included elsewhere in this prospectus for a discussion of factors you should consider before investing in our common stock.

Unless we specifically state otherwise, the information in this prospectus (i) gives effect to the Preferred Stock Conversion; (ii) assumes no exercise by the underwriters of their option to purchase additional shares of common stock; (iii) excludes an aggregate of 551,315 shares of common stock reserved and available for future issuance under our 2005 Stock Incentive Plan and 1,960,310 shares issuable upon exercise of outstanding options at a weighted average exercise price of $8.82 per share as of November 18, 2009; and (iv) is based on 6,421,564 shares outstanding as of November 10, 2009.

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Summary Consolidated Financial Data

The following table presents summary historical consolidated financial data of our business, as of the dates and for the periods indicated. The summary historical consolidated financial data as of and for the year ended December 31, 2008 have been derived from our audited consolidated financial statements and related notes included elsewhere in this prospectus. The summary historical consolidated financial data for the nine months ended September 30, 2008 and 2009 have been derived from our unaudited consolidated financial statements included elsewhere in this prospectus. The September 30, 2008 and 2009 financial statements have been prepared on a basis consistent with our audited consolidated financial statements and reflect all adjustments, consisting of normal recurring adjustments, which are, in the opinion of management, necessary for a fair presentation of the financial position and results of operations for the periods presented.

The summary consolidated financial data should be read in conjunction with Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations, Risk Factors and our consolidated financial statements and related notes included elsewhere in this prospectus.

	Year Ended December 31,			Nine Months Ended September 30,	
	2006	2007	2008	2008	2009
			(In thousands)		
				(unaudited)	
Statement of Operations Data:					
Operating revenues:					
Natural gas sales	$ 10,570	$ 67,868	$ 116,415	$ 92,075	$ 55,135
Crude oil sales	10,908	27,021	41,860	34,150	21,519
Natural gas liquids sales		14,273	27,405	24,687	9,089
Operating overhead and other income	181	381	1,088	889	508
Total operating revenues	21,659	109,543	186,768	151,801	86,251
Operating expenses:					
Lease operating expenses	5,633	12,034	20,825	15,363	13,518
Production and ad valorem taxes	1,895	11,702	16,266	14,355	6,061
Exploration expenses	673	3,174	9,965	1,877	2,873
Depreciation, depletion and amortization	4,035	30,796	50,467	36,030	41,599
Impaired assets of oil and gas properties(1)	3,150	4,362	35,954	25,799	
General and administrative	8,730	14,542	22,406	17,819	13,381
(Gain) loss on sale of assets(2)	2	(683)	(15,210)	(15,272)	19
Total operating expenses	24,118	75,927	140,673	95,971	77,451
Income (loss) from operations(3)	(2,459)	33,616	46,095	55,830	8,800
Other income (expense):					
Interest expense, net of amount capitalized	(109)	(14,949)	(21,109)	(15,871)	(16,349)
Other financing costs	(228)	(1,322)	(1,501)	(1,174)	(1,110)
Loss from equity in investments	(2)				

Unrealized gain (loss) on derivative instruments	6,082	(18,186)	49,409	1,665	(17,238)
Total other income (expense)	5,743	(34,457)	26,799	(15,380)	(34,697)
Income (loss) before income taxes	3,284	(841)	72,894	40,450	(25,897)
Income tax benefit (expense)	(1,425)	410	(26,691)	(15,105)	9,080
Net income (loss)	1,859	(431)	46,203	25,345	(16,817)
Preferred stock dividends	(3,649)	(4,453)	(4,234)	(3,164)	(3,353)
Net income (loss) available to common stockholders	$ (1,790)	$ (4,884)	$ 41,969	$ 22,181	$ (20,170)

	Year Ended December 31, 2006	Year Ended December 31, 2007	Year Ended December 31, 2008	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2009
	(In thousands, except per share data)			*(unaudited)*	
Net Income (Loss) Per Share Information					
Basic					
Weighted average shares outstanding	3,231	4,330	5,371	5,225	6,301
Net income (loss) per share	$ (0.55)	$ (1.13)	$ 7.81	$ 4.25	$ (3.20)
Diluted					
Weighted average shares outstanding	3,231	4,330	10,360	10,289	6,301
Net income (loss) per share	$ (0.55)	$ (1.13)	$ 4.46	$ 2.46	$ (3.20)
Other Financial Data					
Adjusted EBITDAX[4]	$ 9,219	$ 76,003	$ 132,707	$ 108,715	$ 55,160
Capital expenditures[5]					
Other capital expenditures[6]	21,777	59,049	141,795	82,577	(494)
Acquisitions of oil and gas properties	$	$ 253,434	$ 58,482	$ 58,032	$ 16,545
Total	$ 21,777	$ 312,483	$ 200,277	$ 140,609	$ 16,051

	As of September 30, 2009	Pro Forma As Adjusted as of September 30, 2009[7]
Balance Sheet Data (end of period):		
Property and equipment, net	$ 425,236	$
Total assets	462,481	
Long-term debt, including current portion	291,526	
Stockholders equity	106,542	
Total liabilities and stockholders equity	462,481	

(1) For the year ended December 31, 2008, includes (i) an impairment expense of $10.2 million in December 2008 with respect to our Grand Lake Field in Southwest Louisiana, resulting from negative reserve revisions resulting from year end low commodity prices, and (ii) $25.8 million in asset impairments in the nine months ended September 30, 2008 resulting from our capital investment in the Rodessa formation within the Madisonville Field.

(2) For the year ended December 31, 2008 and the nine months ended September 30, 2008, includes a gain of $15.6 million resulting from the disposition of our interest in the Barnett Shale Play in January 2008.

(3) Non-cash equity-based compensation charges were $5.4 million, $4.7 million and $3.8 million, in 2008, 2007 and 2006, respectively. Non-cash equity-based compensation charges were $4.5 million and $1.9 million for the nine months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and

2008, this expense was $1.9 million and $4.5 million, respectively.

(4) Adjusted EBITDAX is a non-GAAP financial measure. Our definition of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX is provided under Non-GAAP Financial Measures and Reconciliations.

(5) Capital expenditures are derived from our consolidated statements of cash flows in our financial statements included elsewhere in this prospectus.

(6) Other capital expenditures consists primarily of capital drilling and lease acquisitions.

(7) On an adjusted pro forma basis to give effect to this offering, the application of the estimated net proceeds of this offering, the Preferred Stock Conversion, the issuance of $12 million in aggregate principal amount of indebtedness under our unsecured promissory notes and the repayment of loans under our revolving credit facility with proceeds of one of such promissory notes.

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Pro Forma Net Income (Loss) Per Share Data

The pro forma data presented in the following table gives effect to the Preferred Stock Conversion.

	Year Ended December 31, 2008	Nine Months Ended September 30, 2009
	(In thousands, except per share data)	
Pro forma preferred stock dividends	$	$
Pro forma net income (loss) available to common stockholders		
Pro forma basic net income (loss) per share:		
Weighted average shares outstanding		
Net income (loss) per share		
Pro forma diluted net income (loss) per share:		
Weighted average shares outstanding		
Net income (loss) per share		

Summary Reserve and Historical Operating Data

The following tables present certain information with respect to our estimated proved natural gas, crude oil and natural gas liquids reserves at year end and operating data for the periods presented. The table shows estimated net proved reserves, based on the reserve reports dated December 31, 2006, 2007 and 2008, substantially all of which were prepared by our independent petroleum engineers. You should refer to Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business Proved Reserves and Business Production, Revenue and Price History when evaluating the material presented below.

	Year Ended December 31,			Nine Months Ended September 30,	
	2006	2007	2008	2008	2009
Production:					
Natural gas (MMcf)	1,542	9,068	13,136	9,753	8,143
Crude oil (MBbl)	185	409	498	385	264
Natural gas liquids (MBbl)		286	516	422	334
Total (MMcfe)	2,652	13,236	19,222	14,598	11,733
Average Sales Prices (Before Hedging):					
Natural gas ($/Mcf)	$ 6.76	$ 6.78	$ 8.92	$ 9.83	$ 3.92
Crude oil ($/Bbl)	$ 63.29	$ 74.38	$ 101.13	$ 112.98	$ 52.80
Natural gas liquids ($/Bbl)		$ 49.92	$ 53.07	$ 58.49	$ 21.19
Natural gas equivalents ($/Mcfe)	$ 8.34	$ 8.02	$ 10.14	$ 11.24	$ 4.68
Average Sales Prices (After Hedging)[1]:					
Natural gas ($/Mcf)	$ 6.85	$ 7.48	$ 8.86	$ 9.44	$ 6.77
Crude oil ($/Bbl)	$ 59.00	$ 66.09	$ 84.03	$ 88.60	$ 81.46
Natural gas liquids ($/Bbl)		$ 49.92	$ 53.07	$ 58.49	$ 27.19
Natural gas equivalents ($/Mcfe)	$ 8.10	$ 8.25	$ 9.66	$ 10.34	$ 7.31
Expenses: ($/Mcfe)					
Lease operating expenses	$ 2.12	$ 0.91	$ 1.08	$ 1.05	$ 1.15
Production and ad valorem taxes	$ 0.71	$ 0.88	$ 0.85	$ 0.98	$ 0.52
Exploration expenses	$ 0.25	$ 0.24	$ 0.52	$ 0.13	$ 0.24
General and administrative	$ 3.29	$ 1.10	$ 1.17	$ 1.22	$ 1.14
Depreciation, depletion and amortization	$ 1.52	$ 2.33	$ 2.63	$ 2.47	$ 3.55
Proved Reserves (end of period)[2]:					
Natural gas (MMcf)	31,388	91,239	96,169		
Crude oil (MBbl)	2,501	2,903	2,564		
Natural gas liquids (MBbl)		3,590	3,399		
Total proved reserves (MMcfe)	46,394	130,197	131,947		
Percent proved developed reserves	88%	75%	69%		
PV-10 value ($ in millions)[3]	$ 102.4	$ 531.4	$ 291.0		
Standardized measure ($ in millions)[4]	77.4	399.5	260.9		

(1) Amounts shown are based on natural gas and crude oil sales, net of realized commodity derivative gains (losses).

(2) The prices utilized in the estimation of our proved reserves and future net revenues, PV-10 and Standardized Measure of Discounted Net Cash Flows were based on the West Texas Intermediate posted prices on

December 31, 2007 and December 31, 2008 of $92.50 and $41.00 per barrel for crude oil, respectively, and the Henry Hub spot market price of $6.80 and $5.71 per MMBtu for natural gas, respectively. The prices utilized in our estimation of our 2006 proved reserves were based on the NYMEX posted price on December 31, 2006 of $61.06 per barrel for crude oil and the

NYMEX spot market price of $6.03 per MMBtu for natural gas. All prices were adjusted by lease for quality, energy content, transportation fees and regional price differentials.

(3) PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure of Discounted Net Cash Flows to PV-10 is provided under Non-GAAP Financial Measures and Reconciliations.

(4) The Standardized Measure of Discounted Net Cash Flows represents the present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

Non-GAAP Financial Measures and Reconciliations

Adjusted EBITDAX

EBITDAX represents net income (loss) before net interest expense, taxes, and depreciation, amortization and exploration expenses. Adjusted EBITDAX represents EBITDAX as further adjusted to reflect the items included in the table below, all of which will be required in determining our compliance with financial covenants under our revolving credit facility and second lien term loan agreement.

We have included EBITDAX and Adjusted EBITDAX in this prospectus to provide investors with a supplemental measure of our operating performance and information about the calculation of some of the financial covenants that are contained in our credit agreements. We believe EBITDAX is an important supplemental measure of operating performance because it eliminates items that have less bearing on our operating performance and so highlights trends in our core business that may not otherwise be apparent when relying solely on generally accepted accounting principles, or GAAP, financial measures. We also believe that securities analysts, investors and other interested parties frequently use EBITDAX in the evaluation of issuers, many of which present EBITDAX when reporting their results. Adjusted EBITDAX is a material component of the covenants that are imposed on us by our revolving credit facility and second lien term loan agreement. We are subject to financial covenant ratios that are or will be calculated by reference to Adjusted EBITDAX. Non-compliance with the financial covenants contained in these credit agreements could result in a default, an acceleration in the repayment of amounts outstanding, and a termination of lending commitments. For a description of required financial covenant levels and actual ratio calculations based on Adjusted EBITDAX, see Management s Discussion and Analysis of Financial Condition and Results of Operations Financial Condition Liquidity and Capital Resources Covenant compliance. Our management and external users of our financial statements, such as investors, commercial banks, research analysts and others, also use EBITDAX and Adjusted EBITDAX to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure; and
- the feasibility of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDAX and Adjusted EBITDAX are not presentations made in accordance with GAAP. As discussed above, we believe that the presentation of EBITDAX and Adjusted EBITDAX in this prospectus is appropriate. However, when evaluating our results, you should not consider EBITDAX and

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Adjusted EBITDAX in isolation of, or as a substitute for, measures of our financial performance as determined in accordance with GAAP, such as net income (loss). EBITDAX and Adjusted EBITDAX have material limitations as performance measures because they exclude items that are necessary elements of our costs and operations. Because other companies may calculate EBITDAX and Adjusted EBITDAX differently than we do, EBITDAX may not be, and Adjusted EBITDAX as presented in this prospectus is not, comparable to similarly-titled measures reported by other companies.

The following table reconciles net income (loss) to EBITDAX and Adjusted EBITDAX for the periods presented:

	Year Ended December 31,					Nine Months Ended September 30,	
	2004	2005	2006	2007	2008	2008	2009
	(In thousands)						
Net income (loss)	$ 8,072	$ (3,543)	$ 1,859	$ (431)	$ 46,203	$ 25,345	$ (16,817)
Interest expense	4,154	1,302	109	14,949	21,109	15,871	16,349
Income tax expense (benefit)	(3,204)	(792)	1,425	(410)	26,691	15,105	(9,080)
Depreciation and amortization	2,257	3,209	4,035	30,796	50,467	36,030	41,599
Exploration expenses	433	750	673	3,174	9,965	1,877	2,873
EBITDAX	$ 11,712	$ 926	$ 8,101	$ 48,078	$ 154,435	$ 94,228	$ 34,924
Unrealized (gain) loss on derivative instruments	1,506	1,642	(6,082)	18,186	(49,409)	(1,665)	17,238
Non-cash equity-based compensation charges		44	3,820	4,738	5,436	4,451	1,869
Impaired assets	61	3,689	3,150	4,362	35,954	25,799	
Other financing[(1)]	1,472	1,956	228	1,322	1,501	1,174	1,110
Forgiveness of debt	(12,476)						
(Gain) loss on the disposition of assets	2,034	39	2	(683)	(15,210)	(15,272)	19
Adjusted EBITDAX	$ 4,309	$ 8,296	$ 9,219	$ 76,003	$ 132,707	$ 108,715	$ 55,160

(1) Includes amortization of deferred finance costs and other fees and expenses payable under our credit agreements.

PV-10

PV-10 is a non-GAAP financial measure and represents the year-end present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes or non-property related expenses such as general and administrative expenses and debt service or depreciation, depletion and amortization on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure to PV-10:

	At December 31, 2006	2007	2008
	(In millions)		
Standardized measure of discounted net cash flows	$ 77.4	$ 399.5	$ 260.9
Present value of future income tax and other discounted at 10%	25.0	131.9	30.1
PV-10	$ 102.4	$ 531.4	$ 291.0

RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risk factors included below as well as the other information contained in this prospectus before investing in our common stock, or deciding whether you will or will not participate in this offering. 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.

Risks Related to Our Business

Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.

Our revenue, cash flow from operations and future growth depend upon the prices and demand for natural gas, crude oil and natural gas liquids. The markets for these commodities are very volatile. Even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas, crude oil and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for natural gas, crude oil and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, crude oil and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas, crude oil and natural gas liquids;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- availability of pipeline infrastructure, treating, transportation and refining capacity;
- domestic and foreign governmental regulations and taxes; and
- the price and availability of alternative fuels.

Lower natural gas and crude oil prices may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas and crude oil that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves.

Our East Texas leases must be drilled before expiration, generally within three years, in order to hold the leases by production. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, Bossier Shale and James Lime formations.

Our East Texas leases have three year terms which require that an initial producing well be drilled prior to expiration date or the lease will terminate. Generally, once an initial well is drilled and completed as a producer, the lease is extended for the duration of production subject to payment of royalties and additional wells may be drilled on that lease. The leases in this area are extremely fragmented and much of the leased acreage is not contiguous. In many cases, contiguous leases owned by us are not large enough to accommodate horizontal drilling to the Haynesville Shale, which usually involves a horizontal lateral of between 4,000 to 5,000 feet within lease lines. In other cases, leases may be from fractional interest land owners and may not comprise a sufficient aggregate percentage working interest to make such a well economic. As a result, in order to realize the drilling opportunities in the Haynesville Shale, Bossier Shale and James Lime formations, we and other similarly situated major lease owners and operators in East Texas will need to cooperate and negotiate joint drilling operations in order to drill initial wells prior to lease expirations. These negotiations may include the right to act as operator for jointly owned wells. If we do not reach agreements with other major lease owners and operators to drill wells prior to lease expirations, or if we are unable to drill timely sufficient wells to hold our acreage, we will lose the drilling opportunities and investment in the expiring leases unless we can successfully negotiate to renew the leases. We may not be able to renew the expired leases, or if renewed, the cost of releasing could be substantial, particularly if development in this area proves successful.

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.

The results of our exploratory drilling in new or emerging plays, such as in our East Texas resource play, 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 less able to use past drilling results in those areas to help predict our future drilling results. To the extent we are unable to execute our expected drilling program in these areas, because of capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services, or otherwise, and/or natural gas and crude oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate and our common stock price may decrease. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

The results of our planned exploratory drilling in our East Texas and South Texas resource plays, which are newly emerging plays with limited drilling and production history, are subject to more uncertainties than our drilling program in our more established areas of operation in the onshore South Texas and U.S. Gulf Coast regions and may not meet our expectations for reserves or production.

We have recently completed drilling our first well in the Haynesville Shale in East Texas, for which we were not operator, as well as a test well in Bee County, South Texas to the Eagle Ford Shale. The exploration of the Haynesville Shale in the East Texas area where we own leases has been limited. Part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling of these shale plays is limited. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, the results of our future drilling in the emerging shale plays are more uncertain than drilling results in our more established areas of operation with established reserves and production history.

Initial production rates in the Haynesville Shale tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

The initial production rate for our first well in our Haynesville acreage was 30.7 MMcfe/d, which we believe to be the highest publicly reported 24-hour initial production rate for a Haynesville

Shale well in Texas or Louisiana. However, initial production rates in the Haynesville Shale tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas, crude oil and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our revolving credit facility. Our cash flow from operations and access to capital is subject to a number of variables, including:

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

If our revenues decrease as a result of lower natural gas, crude oil and natural gas liquids prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels or to further develop and exploit our current properties, or for exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our credit agreements contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base is redetermined resulting in a lower borrowing base under our revolving credit facility, we may be unable to obtain financing otherwise available under our revolving credit facility. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources.

Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Based on a number of economic indicators, global economic activity has slowed substantially. At the present time, the rate at which the global economy will slow has become increasingly uncertain. A continued slowing of global economic growth, and, in particular, economic growth in the United States, will likely continue to reduce demand for natural gas, crude oil and natural gas liquids, which in turn could likely result in lower prices for natural gas, crude oil and natural gas liquids. Natural gas and crude oil prices dropped dramatically from record levels of approximately $13 per

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MMbtu and $145 per barrel, respectively, in July 2008 to below $3 per MMbtu in September 2009 and below $34 per barrel in December 2008. A reduction in demand for, and the resulting lower prices of, natural gas, crude oil and natural gas liquids could adversely affect our results of operations.

Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements.

Recent market events and conditions, including unprecedented disruptions in the current credit and financial markets and the deterioration of economic conditions in the U.S. and internationally have had a significant material adverse impact on a number of financial institutions and have limited access to capital and credit for many companies. These disruptions could, among other things, make it more difficult for us to obtain, or increase our cost of obtaining, capital and financing for our operations. Access to additional capital may not be available on terms acceptable to us or at all. Difficulties in obtaining capital and financing or increased costs for obtaining capital and financing for our operations would have an adverse effect on our ability to fund our working capital and other capital requirements.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

We have incurred net losses in two of the last five fiscal years. We cannot assure you that our current level of operating results will continue or improve. Our activities could require additional debt or equity financing. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of natural gas, crude oil and natural gas liquids, rates of production, timing of capital expenditures and drilling success. Negative changes in these variables could have a material adverse effect on our business, financial condition, results of operations and the market value of our common stock.

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 natural gas and crude oil 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 for information about our crude 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 crude 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, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and crude oil 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. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and crude oil prices and other factors, many of which are beyond our control.

Approximately 31% of our total estimated proved reserves at December 31, 2008 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our natural gas and crude oil reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated natural gas, crude oil and natural gas liquids reserves.

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 natural gas, crude oil and natural gas liquids reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2008 was based on a Henry Hub spot market price of $5.71 per MMbtu for natural gas and a West Texas Intermediate posted price of $41.00 per barrel for crude oil on December 31, 2008. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2008 would have decreased from $290.95 million to $288.15 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of December 31, 2008, would have decreased from $290.95 million to $285.47 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock.

Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Our estimates of proved reserves and related PV-10 and standardized measure of future net cash flows, which are prepared and presented under existing SEC rules, may change materially as a result of new SEC rules that will go into effect for fiscal years ending on or after December 31, 2009.

This prospectus presents estimates of our proved reserves and related PV-10 and standardized measure of future net cash flows as of December 31, 2008, which estimates have been prepared and presented under existing SEC rules. The SEC has adopted new rules that are effective for fiscal years ending on or after December 31, 2009, which will require SEC reporting companies to prepare their reserves estimates using revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing. The SEC has released only limited interpretive guidance regarding reporting of reserve estimates under the new rules and may not issue further interpretive guidance on the new rules prior to the end of 2009. We have not determined the impact the new rules may have on our estimates of our proved reserves and related PV-10 and standardized measure of future net cash flows as of December 31, 2009, but the impact of the new rules on such estimates, and in particular the estimates of proved undeveloped reserves, could be material.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and crude oil. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. For example, we have over 4,200 square miles of 3D data in the South Texas and Gulf Coast regions and 1,130 square miles of 3D data in the Lobo trend in South Texas that our internal prospect generation team uses to develop drilling opportunities in these areas. However, even when used and properly interpreted, 3D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies require greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing natural gas and crude oil are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas and crude oil can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- explosions and blowouts;
- pipe or cement failures;
- environmental hazards, such as natural gas leaks, pipeline ruptures and discharges of toxic gases;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages of skilled personnel;

shortages or delivery delays of equipment and services;

compliance with environmental and other regulatory requirements;

natural disasters; and

adverse weather conditions.

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Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment; pollution; environmental contamination; clean-up responsibilities; loss of wells; repairs to resume operations; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Our acquisition strategy may subject us to greater risks.

The successful acquisition of properties requires an assessment of recoverable reserves, future natural gas and crude oil prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, costs and liabilities, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to fully assess their capabilities or deficiencies. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

We may be unable to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations. The difficulties of integrating these assets and properties present numerous risks, including:

- acquisitions may prove unprofitable and fail to generate anticipated cash flows;
- we may need to (i) recruit additional personnel and, in this competitive labor market, we cannot be certain that any of our recruiting efforts will succeed, and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management; and
- our management s attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing natural gas and crude oil properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing natural gas and crude oil properties that have economically recoverable reserves for acceptable prices.

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We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate a significant portion of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator s breach of the applicable agreements or an operator s failure to act in ways that are in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

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

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory natural gas and crude oil transportation arrangements may hinder our access to natural gas and crude oil markets or delay our production. The availability of a ready market for our crude oil and natural gas production depends on a number of factors, including the demand for and supply of natural gas and crude oil 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 materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our natural gas and crude oil may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

Unless we replace our natural gas and crude oil 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 natural gas and crude oil reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future natural gas and crude oil 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.

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The potential lack of availability or high cost of drilling rigs, equipment, supplies, personnel and crude oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

When the prices of natural gas and crude oil increase, such as during 2008, we encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operation and financial condition.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, crude oil and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a significant portion of our natural gas, crude oil and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil and natural gas liquids production. As of September 30, 2009, we had 13.9 Bcfe of equivalent production hedged representing 1.8 Bcf, 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 86 MBbl, 250 MBbl and 124 MBbl of crude oil hedges in place for the fourth quarter of 2009, 2010 and 2011, respectively. The average price of our natural gas and crude oil hedges in place is $8.19/MMBtu and $86.03/Bbl for the fourth quarter of 2009, $7.71/MMBtu and $83.02/Bbl in the year 2010 and $7.32/MMBtu and $66.50/Bbl in the year 2011. As of September 30, 2009, we had entered into interest rate swap agreements with a total notional amount of $200.0 million related to our indebtedness. Under our interest rate swap agreements, we receive interest at a floating rate equal to one-month LIBOR and pay interest at a fixed rate of 1.50% for $50.0 million and pay interest at 2.90% for $150.0 million.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of our interest rate swap agreements, we may fail to benefit when rates fall, to the extent we have agreed to pay interest at a fixed rate, or face a greater degree of exposure when rates increase, to the extent we have agreed to pay interest at a floating rate. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Competition in the oil and gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing natural gas and crude oil, and securing equipment and trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial our personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. 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.

We depend on our senior management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition and the results of operations and future growth.

Our success is largely dependent on the skills, experience and efforts of our people. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial conditions and results of operations and future growth. These persons include the executive officers listed in Management Executive Officers and Directors. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

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

Our 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 and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local regulations as interpreted and enforced by governmental agencies and other bodies vested with much authority relating to the exploration for, and the development, production, transportation and marketing of, natural gas, crude oil and natural gas liquids. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale formations. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills, which are currently pending in the Energy and Commerce Committee and the Environmental and Public Works Committee of the House of Representatives and Senate, respectively, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased

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operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our operations expose us to potentially substantial costs and liabilities with respect to environmental, health and safety matters.

We may incur substantial costs and liabilities as a result of environmental, health and safety requirements applicable to our crude oil and natural gas operations and other activities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations that cover, among other things, emissions into the air and water, habitat and endangered species protection, the containment and disposal of hazardous substances, oil field waste and other waste materials, the use of underground injection wells, and wetlands protection. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with environmental, health and safety laws or regulations may result in assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and the issuance of orders enjoining or limiting our current or future operations. Compliance with these laws and regulations also increases the cost of our operations and may prevent or delay the commencement or continuance of a given operation.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health, or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations. In addition, many countries, as well as more than one-third of the states have agreed to regulate emissions of greenhouse gases, including methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas and oil. National greenhouse gas legislation and regulation is in early stages of development in the U.S., and we are currently unable to determine the impact of potential greenhouse gas emission control requirements. Mandatory greenhouse gas emissions reductions may impose increased costs on our business and could adversely impact some of our operations. It is possible that broader national or regional greenhouse gas reduction requirements may directly or indirectly have an adverse impact on natural gas or other fuel markets, including future demand for the natural gas, crude oil and natural gas liquids that we produce. See Business Environmental Regulations.

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. For example, for the quarter ended March 31, 2007, our management concluded that our historical documentation of

related tax positions could have resulted in a material misstatement to our annual or interim financial statements and, accordingly, concluded that this deficiency was a material weakness. Although this material weakness was subsequently remedied, if we are unable to successfully prevent or address these and other material weaknesses in our internal control systems, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

Derivatives regulation could restrict our ability to execute commodity derivative instruments as a hedge against fluctuating commodity prices.

Various measures are being proposed by committees of Congress, the U.S. Treasury Department, and other agencies to restrict the use of over-the-counter (OTC) derivative instruments. These proposals include, but are not limited to, requiring cash collateral on all OTC derivatives and requiring all OTC derivatives to be executed and settled through an exchange system.

Although we do not currently know the exact form any final legislation or rule-making activity will take, any restriction on the use of OTC instruments could have a significant impact on our business. Limits on the use of OTC instruments could significantly reduce our ability to execute strategic price hedges against commodity price volatility. In addition, cash collateral requirements could create significant liquidity issues and exchange system trades may restrict our ability to execute derivative instruments to fit our strategic needs.

Risks Related to an Investment in Our Common Stock and this Offering

One stockholder will, after the completion of this offering, hold a significant number of our shares, which will limit your ability to influence corporate activities and may adversely affect the market price of our common stock, and that stockholder s interests may conflict with the interests of our other stockholders.

After completion of the Preferred Stock Conversion and the issuance of shares of common stock in this offering, we expect, based on the midpoint of the range provided on the cover of this prospectus, there will be approximately million shares of our common stock outstanding. Of that amount, we expect that million shares of our common stock will be held by Oaktree Holdings. As a result, Oaktree Holdings will own or control outstanding common stock representing, in the aggregate, an approximate % voting interest in us. As a result of this stock ownership, Oaktree Holdings will possess significant influence over matters requiring approval by our stockholders, including the adoption of amendments to our certificate of incorporation and bylaws and significant corporate transactions. Such ownership and control may also have the effect of delaying or preventing a future change of control, impeding a merger, consolidation, takeover or other business combination or discouraging a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company.

Oaktree Holdings and its affiliates engage, from time to time in the ordinary course of their respective businesses, in the trading securities of, and investing in, energy companies. As a result, conflicts may arise between the interests of Oaktree Holdings, on the one hand, and the interests of our other stockholders, on the other hand. Oaktree Holdings may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. Oaktree Holdings may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us.

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock price may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for natural gas, crude oil and natural gas liquids;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;
- general market, economic and political conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

See Risks Related to Our Business.

In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. 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. Also, the provisions of our revolving credit facility and second lien term loan agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

Upon consummation of this offering and the Preferred Stock Conversion, there will be shares of our common stock outstanding. All shares of our common stock sold in this offering will be freely transferable without restriction or further registration under the Securities Act of 1933, as amended, or the Securities Act. The remaining shares of our common stock outstanding, including the shares of common stock owned by Oaktree Holdings, our directors and executive officers, will be restricted securities within the meaning of Rule 144 under the Securities Act, but, subject to the lock-up agreements described in Underwriting, will be eligible for resale subject to applicable volume, manner of sale, holding period and other limitations of Rule 144. See Shares Eligible for Future Sale for a discussion of the shares of our common stock that may be sold into the public market in the future.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of November 18, 2009, we had 2.0 million options to purchase shares of our common stock outstanding, 1,239,311 of which were vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;

- require business at special meetings to be limited to the stated purpose or purposes of that meeting;

- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and

- permit directors to fill vacancies in our board of directors.

The foregoing factors, as well as the significant common stock ownership by Oaktree Holdings, could discourage potential acquisition proposals and could delay or prevent a change of control. See Description of Capital Stock.

After this offering, we will be subject to the Delaware business combination law.

After this offering, we will be subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a business combination as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an interested stockholder as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation s voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 662/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law. This election would become effective twelve months after the adoption of the amendment and would not apply to any business combination with any person who became an interested stockholder on or before the adoption of the amendment. Section 203 of the Delaware General Corporation Law will not apply to Oaktree Holdings.

We have blank check preferred stock.

Our certificate of incorporation authorizes the board of directors to issue preferred stock without further stockholder action in one or more series and to designate the dividend rate, voting rights and other rights preferences and restrictions. The issuance of preferred stock could have an adverse impact on holders of common stock. Preferred stock is senior to common stock. Additionally, preferred stock could be issued with dividend rights senior to the rights of holders of common stock. Finally, preferred stock could be issued as part of a poison pill, which could have the effect of deterring offers to acquire our company. See Description of Capital Stock Anti-Takeover Effects of Delaware Laws and Our Charter and Bylaws Provisions.

The holders of our common stock do not have cumulative voting rights, preemptive rights or rights to convert their common stock to other securities.

We are authorized to issue 200.0 million shares of common stock, $0.001 par value per share. As of December 31, 2008, there were 5.8 million shares of common stock issued and outstanding. After giving effect to this offering and the Preferred Stock Conversion, there will be million shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities.

Prior to this offering, our common stock has been thinly traded and there has been no active trading market for our common stock and an active trading market may not develop.

The trading volume of our common stock has historically been low and reliable market quotations for our common stock have not been available, partially due to the fact that we are not listed on an exchange and our common stock is only traded over-the-counter. An active trading market for our common stock may not develop or, if developed, may not continue, and a holder of any of our securities may find it difficult to dispose of, or to obtain accurate quotations as to the market value of such securities.

The impairment of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry specifically, with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparty. We have exposure to these financial institutions in the form of derivative transactions in connection with our hedges. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

As of September 30, 2009, pro forma for the application of net proceeds from this offering we had outstanding debt of $ million under our credit agreements. Our substantial level of indebtedness increases the possibility that we may be unable to pay, when due, the principal of, interest on, or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our other financial obligations and contractual commitments, could have other important consequences, including the following:

funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;

we may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;

certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates;

our degree of leverage could make us more vulnerable to downturns in general economic conditions;

our ability to plan for, or react to, changes in our business and the industry in which we operate may be limited; and our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, investments, debt service requirements and other general corporate requirements may be reduced.

In addition, our revolving credit facility and second lien term loan agreement contain a number of significant covenants that place limitations on our activities and operations, including those relating to:

- creation of liens;
- hedging;
- mergers, acquisitions, asset sales or dispositions;
- payments of dividends;
- incurrence of additional indebtedness; and
- certain leases and investments outside of the ordinary course of business.

Our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could also result in a default under our credit agreements. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources for further information regarding future compliance with these covenants. Even if new financing were then available, it may not be on terms that are acceptable to us. See: Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements and Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

Changes to current laws may affect our ability to take certain deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition and results of operations.

Our ability to use our net operating loss carryforwards may be subject to limitation and may result in increased future tax liability to us.

Generally, a change of more than 50% in the ownership of a corporation s stock, by value, over a three-year period constitutes an ownership change for U.S. federal income tax purposes. An ownership change may limit a company s ability to use its net operating loss carryforwards attributable to the period prior to such change. The number of shares of common stock that we issue in connection with this offering may be sufficient, taking into account prior or future shifts in our ownership over a three-year period, to cause us to undergo an ownership change. As a result, if we earn net taxable income, our ability to use our pre-change net operating loss carryforwards to offset U.S. federal taxable income may become subject to limitations, which could potentially result in increased future tax liability to us. In addition, the carrying value of any tax asset related to our net operating loss carryforwards could be significantly reduced.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

We make forward-looking statements throughout this prospectus within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

These forward-looking statements include, but are not limited to, statements regarding:

- estimates of proved reserve quantities and net present values of those reserves;
- estimates of probable and possible reserve quantities;
- reserve potential;
- business strategy;
- estimates of future commodity prices;
- amounts, timing and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and gas industry;
- acquisitions of natural gas and crude oil properties;
- production of crude oil and natural gas reserves;
- exploration prospects;
- wells to be drilled and drilling results;
- operating results and working capital; and
- future methods and types of financing.

Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we believe, expect or anticipate will occur, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. We do not guarantee that the transactions and events described in this prospectus will happen as described (or that they will happen at all). The forward-looking information contained in this prospectus is generally located in the material provided under the headings Business, Risk Factors, and Management s Discussion and Analysis of Financial Condition and Results of Operations but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management s reasonable estimates of future results and trends. For a discussion of risk factors affecting our business, see Risk Factors.

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USE OF PROCEEDS

We estimate that our net proceeds from the sale of shares of our common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses, will be approximately $ million, assuming an offering price of $ per share, which is the midpoint of the range provided on the cover page of this prospectus.

We intend to use the net proceeds from this offering to repay approximately $ million in aggregate principal amount of loans outstanding under our revolving credit facility and $10 million in aggregate principal amount of indebtedness under our $10 million unsecured promissory note due to Wells Fargo Bank, National Association. At November 6, 2009 and after application of proceeds from our $10 million unsecured promissory note, we had $129.5 million of indebtedness outstanding under our revolving credit facility. This indebtedness matures on May 8, 2011, and at November 6, 2009 had a weighted average interest rate of 3.76% per annum. The indebtedness under our $10 million unsecured promissory note bears interest at a rate per annum equal to two-month LIBOR plus 2% and matures on January 15, 2010. For a description of our revolving credit facility and our $10 million unsecured promissory note, please see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources.

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share would increase (decrease) the net proceeds from this offering by approximately $ million, assuming no change in the number of shares offered by us as included on the cover page of this prospectus and after deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

DIVIDEND POLICY

We have never declared or paid cash dividends on our common stock or our preferred stock. Each share of our Series G Preferred Stock is entitled to a quarterly cash dividend, if, as and when declared, that cumulates and compounds quarterly whether or not dividends in a quarter are declared or paid, equal to 8% per annum based on the then-current liquidation preference. Dividends on our Series G Preferred Stock have accumulated since 2005, but have not been declared or paid. As of September 30, 2009, accumulated dividends on the Series G Preferred Stock (which may be converted into shares of our common stock at the current $9.00 conversion price) equaled approximately $17.7 million. Although we have not, and are not required to, pay a cash dividend on our Series H Preferred Stock, we have paid a quarterly dividend of one share of our common stock (as adjusted for our 1-for-10 reverse stock split in September 2006) on our outstanding shares of Series H Preferred Stock, as required by its Certificate of Designations, since 2005. The provisions of our revolving credit facility, second lien term loan agreement and preferred stock restrict the payment of dividends. We currently intend to retain all available funds and any future earnings for use in the operation of our business and to fund future growth. We do not anticipate paying any cash dividends on our common stock in the foreseeable future.

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CAPITALIZATION

The following table sets forth cash and cash equivalents and capitalization as of September 30, 2009:

on a historical basis;

on a pro forma basis to give effect to the Preferred Stock Conversion, the issuance of $12 million in aggregate principal amount of indebtedness under our unsecured promissory notes and the repayment of loans under our revolving credit facility with proceeds of one of such promissory notes; and

on a pro forma basis as further adjusted to give effect to this offering and the application of the estimated net proceeds of this offering.

This table should be read together with Use of Proceeds, Selected Historical Consolidated Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and notes to those statements, in each case, included elsewhere in this prospectus.

	As of September 30, 2009		
	Historical	**Pro Forma**	**Pro Forma As Further Adjusted**[1]
	(In thousands, except per share data)		
Cash and cash equivalents	$	$	$
Total current debt			
Unsecured promissory note			
Current portion of long-term debt	1,526		
	$ 1,526	$	$
Total long-term debt, net of current portion			
Revolving credit facility[2]	140,000		
Second lien term loan agreement	150,000		
Subordinated unsecured promissory note			
	$ 290,000	$	$
Total debt	$ 291,526	$	$
Stockholders equity			
Series G Preferred Stock	$ 1	$	$
Series H Preferred Stock			
Common stock	7		
Additional paid-in capital	97,566		
Retained earnings	9,353		

Treasury stock	(384)		
Total stockholders equity	$ 106,543	$	$
Total capitalization	$ 398,069	$	$

(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 and total stockholders equity by $ million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same.

(2) As of November 6, 2009, and after application of proceeds from our $10 million unsecured promissory note, we had $129.5 million in aggregate indebtedness outstanding under our revolving credit facility. After this offering, we expect that we will have $ million in available borrowing capacity under our revolving credit facility.

MARKET FOR OUR COMMON STOCK

Our common stock is traded on the Over-the-Counter Bulletin Board (the OTCBB) under the symbol CXPO.OB. We have applied to list our common stock on the NASDAQ Global Market under the symbol CXPO.

As of , 2009, the last reported sales price of our common stock on the OTCBB was $ per share of common stock and there were shares of our common stock outstanding held by approximately holders of record. The following table sets forth the range of high and low bid quotation prices per share of our common stock as reported by the OTCBB. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

	Range of Reported High and Low Bid Quotations[(1)]		Average Daily Trading Volume
	High	Low	
2006			
First Quarter	$ 9.50	$ 5.60	4,008
Second Quarter	$ 8.90	$ 6.30	2,497
Third Quarter	$ 7.90	$ 6.40	2,646
Fourth Quarter	$ 7.30	$ 5.20	4,762
2007			
First Quarter	$ 6.20	$ 5.25	2,129
Second Quarter	$ 7.55	$ 5.25	4,046
Third Quarter	$ 8.35	$ 7.15	6,110
Fourth Quarter	$ 19.35	$ 7.65	31,362
2008			
First Quarter	$ 18.50	$ 9.10	22,038
Second Quarter	$ 17.50	$ 8.20	22,773
Third Quarter	$ 16.20	$ 7.23	12,932
Fourth Quarter	$ 7.43	$ 2.85	6,533
2009			
First Quarter	$ 4.60	$ 0.80	5,272
Second Quarter	$ 4.65	$ 1.75	7,173
Third Quarter	$ 4.20	$ 2.26	6,492
Fourth Quarter (through November , 2009)	$	$	

(1) In September 2006, we effected a reverse stock split where each ten shares of outstanding common stock were exchanged for one new share of common stock. All periods presented have been adjusted to reflect the effects of the reverse stock split.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial data as of the dates and for the periods indicated. The selected historical consolidated financial data as of December 31, 2004, 2005, 2006, 2007 and 2008 and for each of the five years in the period ended December 31, 2008 have been derived from our audited consolidated financial statements and related notes included elsewhere in this prospectus. The historical consolidated financial data for the nine months ended September 30, 2008 and 2009 have been derived from our unaudited consolidated financial statements and, in the opinion of our management, have been prepared on a basis consistent with our audited consolidated financial statements and reflect all adjustments, consisting of normal recurring adjustments necessary for a fair presentation of the financial position and results of operations for the periods presented. The consolidated results of operations for any period are not necessarily indicative of the results to be expected for any future period. The selected historical consolidated financial data provided below should be read in conjunction with, and are qualified by reference to, Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes thereto included elsewhere in this prospectus.

	Year Ended December 31,					Nine Months Ended September 30,	
	2004	**2005**	**2006**	**2007**	**2008**	**2008**	**2009**
						(Unaudited)	
	(In thousands, except per share data)						
Statement of Operations Data							
Operating revenues	$ 11,208	$ 17,683	$ 21,659	$ 109,543	$ 186,768	$ 151,801	$ 86,251
Operating expenses							
Lease operating expenses	4,613	5,334	5,633	12,034	20,825	15,365	13,518
Production and ad valorem taxes	267	251	1,895	11,702	16,266	14,355	6,061
Exploration expenses	433	750	673	3,174	9,965	1,877	2,873
Depreciation, depletion and amortization	2,257	3,209	4,035	30,796	50,467	36,030	41,599
Impaired assets of oil and gas properties[(1)]	61	3,689	3,150	4,362	35,954	25,799	
General and administrative expenses	2,019	3,773	8,730	14,542	22,406	17,819	13,381
Loss (gain) on sale of assets[(2)]	2,034	39	2	(683)	(15,210)	(15,272)	19
Total operating expenses	11,684	17,045	24,118	75,927	140,673	95,973	77,451
Income (loss) from operations[(3)]	(476)	638	(2,459)	33,616	46,095	55,828	8,800

Other income (expense)							
Interest expense	(4,154)	(1,302)	(109)	(14,949)	(21,109)	(15,871)	(16,349)
Other financing costs	(1,472)	(1,956)	(228)	(1,322)	(1,501)	(1,172)	(1,110)
Loss from equity in investments		(72)	(2)				
Unrealized gain (loss) on derivative instruments	(1,506)	(1,642)	6,082	(18,186)	49,409	1,665	(17,238)
Forgiveness of debt	12,476						
Total other income (expense)	5,344	(4,972)	5,743	(34,457)	26,799	(15,378)	(34,697)
Income (loss) before income taxes	4,868	(4,334)	3,284	(841)	72,894	40,450	(25,897)
Income tax benefit (expense)	3,204	792	(1,425)	410	(26,691)	(15,105)	9,080)
Net income (loss)	8,072	(3,543)	1,859	(431)	46,203	25,345	(16,817)
Preferred stock dividends	(456)	(3,562)	(3,649)	(4,453)	(4,234)	(3,164)	(3,353)
Net income (loss) available to common stockholders	$ 7,617	$ (7,105)	$ (1,790)	$ (4,884)	$ 41,969	$ 22,181	$ (20,170)

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	Year Ended December 31,					Nine Months Ended September 30,	
	2004	2005	2006	2007	2008	2008	2009
						(Unaudited)	
	(In thousands, except per share data)						
Net Income Per Share Information							
Basic							
Weighted average shares outstanding	1,854	2,674	3,231	4,330	5,371	5,225	6,301
Net income (loss) per share	$ 4.11	$ (2.66)	$ (0.55)	$ (1.13)	$ 7.81	$ 4.25	$ (3.20)
Pro forma weighted average shares outstanding							
Pro forma net income (loss) per share	$	$	$	$	$	$	$
Diluted							
Weighted average shares outstanding	3,162	2,674	3,231	4,330	10,360	10,289	6,301
Net income (loss) per share	$ 2.41	$ (2.66)	$ (0.55)	$ (1.13)	$ 4.46	$ 2.46	$ (3.20)
Pro forma weighted average shares outstanding							
Pro forma net income (loss) per share	$	$	$	$	$	$	$
Balance Sheet Data							
Current assets	$ 3,809	$ 5,825	$ 4,232	$ 36,481	$ 46,348	$ 42,195	$ 29,529
Property and equipment, net	50,123	54,223	76,547	356,489	449,156	417,977	425,236
Noncurrent assets	3,944	3,067	3,924	5,965	16,043	7,536	7,716
Total assets	57,876	63,115	84,703	398,935	511,546	467,708	462,481
Current liabilities	37,249	6,856	10,932	48,879	83,990	67,441	41,394
Long-term liabilities	1,950	3,454	12,445	280,403	305,933	300,361	314,545
Total stockholders equity	18,677	52,805	61,326	69,653	121,623	99,906	106,542
Total liabilities and stockholders equity	$ 57,876	$ 63,115	$ 84,703	$ 398,935	$ 511,546	$ 467,708	$ 462,481
Other Financial Data							
Adjusted EBITDAX(4)	$ 4,309	$ 8,386	$ 9,219	$ 76,003	$ 132,707	$ 108,715	$ 55,160
Capital expenditures							
Acquisition of oil and gas properties	$	$	$	$ 253,434	$ 58,482	$ 58,032	$ 16,545
Other capital expenditures(5)	6,142	10,798	21,777	59,049	141,795	82,577	(494)

Total	$ 6,142	$ 10,798	$ 21,777	$ 312,483	$ 200,277	$ 140,609	$ 16,051

(1) For the year ended December 31, 2008, includes (i) an impairment expense of $10.2 million in December 2008 with respect to our Grand Lake Field in Southwest Louisiana, resulting from negative reserve revisions resulting from low year end low commodity prices, and (ii) $25.8 million in asset impairments in the nine months ended September 30, 2008 resulting from our capital investment in the Rodessa formation within the Madisonville Field.

(2) For the year ended December 31, 2008 and the nine months ended September 30, 2008, includes a gain of $15.6 million resulting from the disposition of our interest in the Barnett Shale Play in January 2008.

(3) Non-cash equity-based compensation charges were $5.4 million, $4.7 million and $3.8 million, in 2008, 2007 and 2006, respectively. Non-cash equity-based compensation charges were $4.5 million and $1.9 million for the nine months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, this expense was $1.9 million and $4.5 million, respectively.

(4) Adjusted EBITDAX is a non-GAAP financial measure. Our definition of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX is provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations.

(5) Other capital expenditures consists primarily of capital drilling and lease acquisitions.

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

You should read the following discussion of our results of operations and financial condition with the Selected Historical Consolidated Financial Data and the historical financial statements and related notes included elsewhere in this prospectus. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the Risk Factors section of this prospectus. Actual results may differ materially from those contained in any forward-looking statements.

Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and early 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009. This well targeted the Haynesville Shale and initially produced 30.7 MMcfe/d, which we believe to be the highest publicly announced initial production rate to date in that formation. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Bossier Shale and James Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 net acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009, and we are preparing to complete the well in the Eagle Ford Shale.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of over 800 drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2008, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 131.9 Bcfe, consisting of 96.2 Bcf of natural gas and 6.0 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2008, 73% of our proved reserves were natural gas, 69% were proved developed and 81% were attributed to wells and properties operated by us. From 2006 to 2008, we grew our estimated proved reserves from 46.4 Bcfe to 131.9 Bcfe. In addition, we grew our average daily production from 7.3 MMcfe/d for the year ended December 31, 2006 to 43.0 MMcfe/d for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, we generated $55.2 million of Adjusted EBITDAX. Our definition of the non-GAAP financial measure of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX are provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations. For the same period, our net income (loss) was $(16.8) million.

Recent Developments

East Texas Acreage Acquisition

In the second half of 2008 and early 2009, we obtained natural gas and crude oil leases from mineral interest owners covering approximately 17,000 gross (12,000 net) acres in the natural gas resource play in East Texas specifically in San Augustine and Sabine Counties. We commenced our first well (the Kardell #1H), in which we owned a 52% working interest, in this play in late June 2009 and completed that well in October 2009. The well had a measured depth of approximately 18,350 feet and was a successful test of the Haynesville Shale formation. The initial 24-hour production experienced from the Kardell #1H well in early November 2009 was 30.7 MMcfe/d (12.0 MMcfe/d net to our interest). We plan to continue to pursue an active drilling program in this area for the next several years, targeting primarily the Haynesville Shale, the Bossier Shale and the James Lime formations. We financed the acquisition of this acreage with cash flows from operations and from borrowings available under our revolving credit facility.

Smith Acquisition

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith Production Inc. (Smith) for a purchase price of $65.0 million with an economic effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.4 million for the period between the effective date and the closing date, the cash consideration was approximately $57.6 million. The assets acquired consist of a 25% non-operated working interest in the Samano Field located in Starr and Hidalgo Counties, a 100% operated working interest in the North Bob West Field in Zapata County and 100% operated working interests in the Brushy Creek and Hope Fields in DeWitt County. We acquired an interest in over 16,000 gross acres with these fields, most of which is held by production. Production from the acquired assets was averaging approximately 7 MMcfe/d at closing, which resulted in a 13% increase in our then current net daily production.

The adjusted price for this acreage, with adjustment of the reserves for approximately one Bcfe of production for the interim operations between the effective date and closing, represents a purchase cost of $2.82 per Mcfe for approximately 21 Bcfe of proved reserves and $8,300 per Mcfe of current average daily production. We financed this acquisition with cash flows from operations, proceeds from the sale of assets and from borrowings available under our revolving credit facility. For the year ended December 31, 2008, seven months of revenues and expenses, $11.7 million and $3.7 million, respectively, were included in our financial results of operations.

Barnett Shale Disposition

In January 2008, we and our operator-partner entered into a series of agreements to sell our interests in wells and undeveloped acreage in the Fort Worth Barnett Shale Play in Johnson and Tarrant Counties, Texas to another industry participant active in that area. We owned a 12.5% non-operated working interest in the assets being sold and had 1.5 Bcfe in proved reserves at December 31, 2007. The total consideration paid by the buyer was based on existing wells and undeveloped acreage owned by us and our partner at the time of the final closing. Our share of the consideration received was approximately $34.4 million. Proceeds received for our interest were primarily used to repay amounts outstanding under our revolving credit facility and to help finance our acquisition of the properties from Smith. Our net book value of the assets sold was $18.8 million, which resulted in a gain of $15.6 million.

Promissory Notes

On November 6, 2009, we issued an unsecured promissory note in the aggregate principal amount of $10.0 million to Wells Fargo Bank, National Association and an unsecured subordinated promissory note in the aggregate principal amount of $2.0 million to Oaktree Holdings, our majority stockholder. See Liquidity and Capital Resources Capital resources.

Selected Factors That Affect Our Operating Results

Our revenue, cash flow from operations and future growth depend substantially upon the prices and demand for natural gas, crude oil and natural gas liquids, the quantity of our natural gas, oil and natural gas liquids production and changes in the fair value of derivative instruments we use to reduce the volatility of the prices we receive for our natural gas, oil and natural gas liquids production. Crude oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Even relatively modest drops in prices can significantly affect our financial position and results of operations, the value of our reserves, the quantities of crude oil and gas that we can economically produce and our ability to access capital.

Commodity Prices. Commodity prices have been volatile over the past several years. Significant factors that will impact near-term commodity prices include the following:

- the domestic and foreign supply of and demand for crude oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- political and economic conditions and events in foreign oil and gas producing countries, including those in the Middle East, South America and Russia;
- actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost and availability of oil and gas pipelines and other transportation facilities to our production, and access to readily available alternatives in the event of disruptions in such pipelines or facilities; and
- the price and availability of alternative fuels.

Prior to mid-2008, the oil and gas industry saw significant increases in activity resulting from high commodity prices for natural gas, crude oil and natural gas liquids. However, since mid-2008 commodity prices have declined significantly, which has adversely affected our results of operations. Supply and geopolitical uncertainties resulted in significant price volatility during 2008 with oil prices rising during the first half of the year to record levels before falling by approximately 68% during the second half of the year. Commodity prices, particularly gas prices, continued to decline during the first quarter of 2009. Spot prices for West Texas Intermediate (WTI) oil averaged $99.92/Bbl during 2008, with a low price of $31.41/Bbl in December 2008 and a high price of $145.29/Bbl in July 2008. During 2008, the gas market continued to be driven by high storage inventories and mild weather conditions across much of the country. Spot prices for Henry Hub gas averaged $8.89/MMbtu for the year, with a low price of $5.38/MMbtu in December 2008 and a high price of $13.31/MMbtu in July 2008. Spot prices for WTI oil averaged $68.14/Bbl and Henry Hub gas averaged $3.17/MMbtu during the third quarter of 2009. The NYMEX futures prices for oil and gas were $44.60/Bbl and $5.62/MMbtu at December 31, 2008 and $77.00/Bbl and $5.05/MMbtu at October 30, 2009. The current global recession has had a significant impact on commodity prices and our operations. If commodity prices remain depressed or decline further, this could negatively affect our ability to execute our growth strategy and generate cash flows. See Risk Factors Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth and Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Reserves. As is typical for businesses engaged in the exploration and production of crude oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, natural gas, crude oil and natural gas liquids production from a given well decreases. Thus, unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as they are produced. Our future natural gas, crude oil and natural gas liquids 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.

As of December 31, 2008, we had 131.9 Bcfe of estimated net proved reserves with an associated PV-10 of $291.0 million, representing an increase in reserves of 1.7 Bcfe from December 31, 2007, and an increase in reserves of 85.6 Bcfe from December 31, 2006, resulting primarily from our May 2007 acquisition of properties (STGC Properties) from EXCO Resources, Inc. (EXCO). For a discussion of PV-10 and a reconciliation to Standardized Measure of Discounted Net Cash Flows, see Prospectus Summary Non-GAAP Financial Measures and Reconciliations. Based on our internal estimates, we believe that our proved reserves as of September 30, 2009 compared to December 31, 2008 have declined for a number of reasons, many of which are beyond our control. During the first nine months of 2009, declining commodity prices, reductions in production enhancing capital expenditures, as well as capital expenditures associated with our exploitation and development activities contributed to a decline in our proved reserves from December 31, 2009, as have normal production, operations, and certain property sales made throughout 2009. Estimates of net proved reserves are inherently imprecise. In addition, approximately 31% of our total estimated proved reserves at December 31, 2008 were undeveloped. By their nature, estimates of undeveloped reserves are less certain than proved developed reserves. Recovery of such reserves will require significant capital expenditures and successful drilling operations. See Risk Factors 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. Our level of exploratory capital expenditures for the majority of 2009 was limited due to low commodity prices and limited access to the capital markets, and we deferred major capital allocation for drilling opportunities during the year.

Revenues and Production. Our revenues, net of the realized effects of our hedging instruments, decreased to $85.7 million in the nine months ended September 30, 2009 from $151.0 million in the nine months ended September 30, 2008, a decrease of 43.2%, due to an approximate 20% decrease in production and an approximate 29% decline in realized commodity prices. Revenues, net of the realized effects of our hedging instruments, decreased to $26.7 million for the three months ended September 30, 2009 from $53.1 million for the three months ended September 30, 2008, due to an approximate 29% decrease in production and an approximate 29% decline in realized commodity prices. In the nine month period ended September 30, 2009 our production was 11.7 Bcfe as compared to 14.6 Bcfe for the nine months ended September 30, 2008, or a decrease of 19.6%. This decrease was primarily due to natural field decline and limited production enhancing capital expenditure activity in the first nine months of 2009. On a daily basis, we produced an average of 43.0 MMcfe/d in the first nine months of 2009 compared to an average of 53.3 MMcfe/d in the first nine months of 2008. In the three month period ended September 30, 2009, our production decreased by 1.5 Bcfe, to 3.5 Bcfe from 5.0 Bcfe for the third quarter of 2009, or 30%, primarily due to natural field decline and limited production enhancing capital expenditure activity during 2009. On a daily basis, we produced an average of 38.3 MMcfe/d for the third quarter of 2009 compared to an average of 54.1 MMcfe/d for the third quarter of 2008.

For the year ended December 31, 2008, revenues, net of the realized effects of our hedging instruments, increased to $185.7 million from $109.2 million in 2007 and from $21.5 million in 2006. The increase in 2008 compared to 2007 was primarily due to increases in net realized commodity prices, the success experienced in our drilling program, the full-year effect of our May 2007 acquisition of the STGC Properties from EXCO and the seven-month effect of the May 2008 South Texas

acquisition from Smith, offset by lost production and natural gas liquids not processed, due to Hurricanes Gustav and Ike. Production volumes increased to 19.2 Bcfe in 2008 from 13.2 Bcfe in 2007, representing a 6.0 Bcfe, or 45.2%, increase. Realized prices (net of hedges) were $9.66 per Mcfe in 2008 as compared to $8.25 in 2007. The increase in revenues in 2007 compared to 2006 was primarily due to our acquisition of the STGC Properties from EXCO in May of 2007. Production volumes increased approximately 399.2% during 2007 as compared to 2006 with average daily volumes of 36,264 Mcfe in 2007 compared to an average of 7,265 Mcfe in 2006.

Derivative Instruments. To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, we generally enter into derivative arrangements for a significant portion of our natural gas, crude oil and natural gas liquids production. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk and Derivative Instruments. While these derivative contracts will protect us when market prices are below our contract prices, they also prevent us from realizing an increase in cash flow when market prices are higher than our contract prices. We will sustain realized and unrealized losses to the extent our contract prices are lower than market prices and conversely, we will sustain realized and unrealized gains to the extent our contract prices are higher than market prices. Our derivatives contracts are not designated as accounting hedges and, as a result, gains or losses on derivatives contracts are recorded as an other expense. Internally, our management views the settlement of such derivatives contracts as adjustments to the price received for natural gas, crude oil and natural gas liquids production to determine realized prices.

Net of the realized effect of our hedging agreements, the price received for natural gas for the nine month period ended September 30, 2009 was $6.77 per Mcf, the price received for crude oil was $81.46 per Bbl, and the price received for natural gas liquids was $27.19 per Bbl, or $7.31 per Mcfe on a combined equivalent basis. Before the realized effect of our hedges, the price received for natural gas for the nine month period ended September 30, 2009 was $3.92 per Mcf, the price received for crude oil was $52.80 per Bbl, and the price received for natural gas liquids was $27.19 per Bbl, or $4.68 per Mcfe on a combined equivalent basis.

We realized gains of $7.6 million on our crude oil hedges and $23.2 million on our natural gas hedges in the first nine months of 2009, compared to realized losses of $9.4 million for crude oil hedges and $3.8 million for natural gas hedges in the first nine months of 2008. During the nine month period ended September 30, 2009, we reported a $17.2 million non-cash unrealized loss on our derivatives positions compared to $1.7 million non-cash unrealized gain for the same period of 2008. We realized losses of $8.5 million on our crude oil hedges and $0.8 million on our natural gas hedges in 2008, compared to realized losses of $3.4 million for crude oil hedges and realized gains of $6.4 million for natural gas hedges in 2007, and a loss of $0.8 million for crude oil hedges and a realized gain of $0.2 million for natural gas hedges in 2006. During 2008, we reported a non-cash unrealized gain of $49.4 million compared with a non-cash unrealized loss of $18.2 million for 2007, and a $6.1 million non-cash unrealized gain for 2006. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative positions during the period. The change in fair value is principally measured based on period end prices as compared to the contract price. Future volatility in natural gas, crude oil and natural gas liquids prices could have an adverse effect on the operating results of our results of operations.

Operating Expenses. In evaluating our operations, we frequently monitor and assess our operating expenses, in terms of absolute dollars and on a per Mcfe basis. We believe that this measure allows us to better evaluate our operating efficiency and is used by us in reviewing the economic feasibility of a potential acquisition or development project. Operating expenses are the costs incurred in the operation of producing properties. Expenses for utilities, direct labor, water injection and disposal, production taxes and materials and supplies comprise the most significant portion of our operating expenses. A majority of our operating cost components are variable and increase or decrease as the level of production increases or decreases. Certain items, however, such as direct labor and

materials and supplies, generally remain relatively fixed and do not fluctuate with changes in production volumes, but can fluctuate depending on activities performed during a specific period.

Our decrease in revenues for the nine months ended September 30, 2009 was offset by a decrease in our operating expenses, primarily due to the implementation of cost reduction initiatives in 2009 in response to a lower commodity price environment and lower production and realized prices in 2009. However, our exploration expense increased by $1.0 million, or 52.6%, from $1.9 million for the nine months ended September 30, 2008 to $2.9 million for the nine months ended September 30, 2009, primarily due to higher geological and geophysical costs, abandoned property, lease rentals and settled asset retirement costs incurred in the first nine months of 2009. Similarly, depreciation, depletion and amortization (DD&A) increased from $36.0 million for the nine months ended September 30, 2008 to $41.6 million for the nine months ended September 30, 2009, primarily due to a higher DD&A rate resulting from the effect of negative price-related revisions, partially offset by lower production in 2009.

The increase in our revenue for 2008 as compared to 2007 was offset by an increase of $47.8 million, or 66.2%, in our operating expenses, primarily due to increased costs and expenses resulting from the acquisition of properties from EXCO and Smith and higher production and realized prices Similarly, the increase in our revenue for 2007 as compared to 2006 was offset by an increase of $51.3 million, or 245.5%, in our operating expenses, primarily due to increased costs and expenses resulting from the acquisition of the STGC properties from EXCO.

After application of approximately $ in net proceeds from this offering (estimated based upon the midpoint of the range of the offering price on the cover of this prospectus), we expect to have approximately $ million of available borrowing capacity under our revolving credit facility to pursue our 2010 drilling program. Our 2010 capital budget is approximately $55 million, exclusive of acquisitions, of which we expect to spend approximately 76% of our budget on our East Texas and South Texas resource plays and 24% on our existing producing assets. We plan to drill 12 gross (6.0 net) wells in 2010, including 7 gross (3.0 net) wells on our East Texas resource play acreage, one gross (0.4 net) well on our South Texas resource play acreage, and 4 gross (2.6 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, commodity prices, availability of capital and drilling and production results. We cannot assure you that our exploration and development activities will result in increases in our proved reserves.

Results of Operations

The following discussion is of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial

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Statements and the Notes thereto contained elsewhere in this prospectus. Comparative results of operations for the periods indicated are discussed below.

Nine Months Ended September 30, 2009 Compared to Nine Months Ended September 30, 2008

Revenues

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
	(In millions, except percentages)			
Revenues:				
Natural gas sales	$ 55.1	$ 92.1	$ (37.0)	−40.2%
Crude oil sales	21.5	34.2	(12.7)	−37.1%
Natural gas liquids sales	9.1	24.7	(15.6)	−63.2%
Product revenues	$ 85.7	$ 151.0	$ (65.3)	−43.2%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, were $85.7 million for the first nine months of 2009 compared to $151.0 million for the first nine months of 2008 due to an approximate 20% decrease in production and an approximate 29% decline in realized commodity prices.

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	8,142,588	9,752,667	(1,610,079)	−16.5%
Crude oil (Bbl)	264,170	385,458	(121,288)	−31.5%
Natural gas liquids (Bbl)	334,303	422,107	(87,804)	−20.8%
Natural gas equivalents (Mcfe)	11,733,426	14,598,057	(2,864,631)	−19.6%

Production was approximately 11.7 Bcfe for the first nine months of 2009 compared to approximately 14.6 Bcfe for the first nine months of 2008. On a daily basis, we produced an average of 43.0 MMcfe/d in the first nine months of 2009 compared to an average of 53.3 MMcfe/d in the first nine months of 2008. Production volumes decreased primarily due to natural field decline and limited production-enhancing capital expenditure activity in the first nine months of 2009.

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
Average sales prices (before hedging):				

Natural gas (Mcf)	$ 3.92	$ 9.83	$ (5.91)	−60.1%
Crude oil (Bbl)	52.80	112.98	(60.18)	−53.3%
Natural gas liquids (Bbl)	27.19	58.49	(31.30)	−53.5%
Natural gas equivalents (Mcfe)	4.68	11.24	(6.56)	−58.4%
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 6.77	$ 9.44	$ (2.67)	−28.3%
Crude oil (Bbl)	81.46	88.60	(7.14)	−8.1%
Natural gas liquids (Bbl)	27.19	58.49	(31.30)	−53.5%
Natural gas equivalents (Mcfe)	7.31	10.34	(3.03)	−29.3%

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Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $7.6 million on our crude oil hedges and $23.2 million on our natural gas hedges in the first nine months of 2009, compared to realized losses of $9.4 million for crude oil hedges and $3.8 million for natural gas hedges in the first nine months of 2008.

Costs and Expenses

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
	(In millions, except percentages)			
Certain Operating Expenses:				
Lease operating expenses	$ 13.5	$ 15.4	$ (1.9)	–12.3%
Production and ad valorem taxes	6.1	14.4	(8.3)	–57.6%
Exploration expenses	2.9	1.9	1.0	52.6%
General and administrative[(1)]	11.5	13.3	(1.8)	–13.5%
Operating expenses (cash)	34.0	45.0	(11.0)	–24.4%
Depreciation, depletion and amortization	41.6	36.0	5.6	15.6%
Share-based compensation[(1)]	1.9	4.5	(2.6)	–57.8%
Certain operating expenses[(2)]	$ 77.5	$ 85.5	$ (8.0)	–9.4%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

(2) Exclusive of impairments and sales.

	Nine Months Ended September 30,			
	2009	2008	Change	Percent Change
	(In millions, except percentages)			
Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 1.15	$ 1.05	$ 0.10	9.5%
Production and ad valorem taxes	0.52	0.98	(0.46)	–46.9%
Exploration expenses	0.24	0.13	0.11	84.6%
General and administrative[(1)]	0.98	0.91	0.07	7.6%
Operating expenses (cash)	2.89	3.07	(0.18)	–5.8%
Depreciation, depletion and amortization	3.55	2.47	1.08	43.7%
Share-based compensation[(1)]	0.16	0.31	(0.15)	–48.4%
Selected costs	$ 6.60	$ 5.85	$ 0.75	12.8%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations.

Lease Operating Expenses. Lease operating expenses for the first nine months of 2009 were $13.5 million, compared to $15.4 million in the first nine months of 2008, a decrease primarily due to the implementation of cost reduction initiatives in 2009 in response to the lower commodity price environment, offset by the incremental costs in 2009 related to producing properties acquired from Smith at the end of May 2008.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for the first nine months of 2009 were $6.1 million, compared to $14.4 million for the first nine months of 2008, due to lower production and lower realized prices in 2009 and state tax credits net to us of

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$0.4 million as a result of our focus on maximizing allowable deductions and opportunities for tax relief for prior periods.

Exploration Expenses. Exploration expenses were $2.9 million in the first nine months of 2009 compared to $1.9 million for the first nine months of 2008. The increase in exploration expenses was primarily due to higher geological and geophysical costs, abandoned property, lease rentals and settled asset retirement costs incurred in the first nine months of 2009.

Depreciation, Depletion and Amortization. DD&A expense for the first nine months of 2009 was $41.6 million compared to $36.0 million for the first nine months of 2008, primarily due to a higher DD&A rate resulting from the effect of negative price related reserve revisions, partially offset by lower production in 2009.

Impairment of Oil and Gas Properties. Impairment expense for the first nine months of 2009 was zero compared to $25.8 million for the first nine months of 2008. The 2008 impairment relates primarily to our capital investment made in pursuing the Rodessa formation within the Madisonville Field. Negative performance-related reserve revisions, including the abandonment of the Rodessa formation in the Johnston 2U well, triggered an evaluation of the Madisonville Field for impairment purposes. Given the high original cost of drilling and developing the field and the high cost of producing and processing sour gas, combined with lower commodity prices, our evaluation resulted in the recorded costs of this field exceeding the estimated future undiscounted cash flow of the reserves as of the end of the third quarter 2008.

General and Administrative (G&A) Expenses. Total G&A expenses were $13.4 million for the first nine months of 2009 compared to $17.8 million for the first nine months of 2008, which includes non-cash stock expense of $1.9 million ($0.16 per Mcfe) and $4.5 million ($0.31 per Mcfe) for the first nine months of 2009 and 2008, respectively. The reduction in G&A expenses is primarily a result of implementing cost reduction initiatives during 2009.

Gain on Sale of Assets. We sold minimal assets during the first nine months of 2009, while the gain on the sale of assets in the first nine months of 2008 was $15.3 million primarily due to the disposition of our interest in the Barnett Shale Play in January 2008.

Interest Expense. Interest expense was $16.3 million for the first nine months of 2009, compared to $15.9 million for the first nine months of 2008. Total interest expense increased primarily due to higher debt balances and higher interest rates on our second lien term loan agreement. Total interest expense capitalized for the first nine months of 2009 and 2008 was approximately $25,000 and $0.8 million, respectively.

Other Financing Costs. Other financing costs were $1.1 million for the first nine months of 2009 compared with $1.2 million for the first nine months of 2008. These expenses are comprised primarily of the amortization of capitalized costs associated with our credit agreements and to commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging contracts and our interest rate swaps. This non-cash unrealized loss for the first nine months of 2009 was $17.2 million compared with a non-cash unrealized gain of $1.7 million for the first nine months of 2008. Unrealized gain or loss will vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $25.9 million for the first nine months of 2009 compared to net income before taxes of $40.4 million in the first nine months of 2008. After adjusting for permanent tax differences, we recorded income tax benefit of $9.1 million for the first nine months of 2009, compared to income tax expense of $15.1 million for the first nine months of 2008.

Dividends on Preferred Stock. Dividends on preferred stock were $3.4 million for the first nine months of 2009 compared with $3.2 million in the first nine months of 2008. Dividends in the first nine months of 2009 included approximately $3.3 million on the Series G Preferred Stock and $19,565 on the Series H Preferred Stock. Dividends in the first nine months of 2008 included $3.1 million on the Series G Preferred Stock, and $78,000 on the Series H Preferred Stock. Until such time as the board of directors declares and pays dividends on our Series G Preferred Stock, dividends shall continue to accumulate. Dividends on our Series H Preferred Stock are declared quarterly by our Board of Directors, and as such, are paid out in shares of our common stock during the following period.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Revenues

	Year Ended December 31,			
	2008	2007	Change	Percent Change
	(In millions, except percentages)			
Revenues:				
Natural gas sales	$ 116.4	$ 67.9	$ 48.5	71.4%
Crude oil sales	41.9	27.0	14.9	55.2%
Natural gas liquids sales	27.4	14.3	13.1	91.6%
Product revenues	$ 185.7	$ 109.2	$ 76.5	70.1%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, increased by 70.1%, to $185.7 million in 2008 compared to $109.2 million in 2007. The increase in net revenues was primarily due to increases in net realized commodity prices, the success experienced in our drilling program, the full-year effect of the May 2007 acquisition of the STGC Properties and the seven-month effect of the May 2008 South Texas acquisition from Smith, offset by lost production, and natural gas liquids not processed, due to Hurricanes Gustav and Ike.

	Year Ended December 31,			
	2008	2007	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	$ 13,135,509	$ 9,067,777	$ 4,067,732	44.9%
Crude oil (Bbl)	498,143	408,864	89,279	21.8%
Natural gas liquids (Bbl)	516,352	285,907	230,445	80.6%
Natural gas equivalents (Mcfe)	$ 19,222,479	$ 13,236,403	$ 5,986,076	45.2%

For 2008, sales volumes increased approximately 45.2% compared to production in 2007. We had approximately 425,000 Mcfe of production deferred in the third and fourth quarters of 2008 due to Hurricanes Gustav and Ike. On a daily basis we produced an average of 52.5 MMcfe/d in 2008 compared to an average of 36.3 MMcfe/d in 2007.

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	Year Ended December 31,			
	2008	2007	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 8.92	$ 6.78	$ 2.14	31.6%
Crude oil (Bbl)	101.13	74.38	26.75	36.0%
Natural gas liquids (Bbl)	53.07	49.92	3.15	6.3%
Natural gas equivalents (Mcfe)	10.14	8.02	2.12	26.4%
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 8.86	$ 7.48	$ 1.38	18.4%
Crude oil (Bbl)	84.03	66.09	17.94	27.1%
Natural gas liquids (Bbl)	53.07	49.92	3.15	6.3%
Natural gas equivalents (Mcfe)	9.66	8.25	1.41	17.1%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized losses of $8.5 million on our crude oil hedges and $0.8 million on our natural gas hedges in 2008, compared to realized losses of $3.4 million for crude oil hedges and realized gains of $6.4 million for natural gas hedges in 2007.

Operating Overhead and Other Income. Revenues from working interest partners increased to $1.1 million in 2008 compared to $0.4 million in 2007 due to the increase in administrative overhead fees charged to our partners on the operated acquired properties and the one-time catch up in the third quarter 2008 on overhead billings due to the increase in COPAS rates.

Costs and Expenses

	Year Ended December 31,			
	2008	2007	Change	Percent Change
	(In millions, except percentages)			
Operating Expenses:				
Lease operating expenses	$ 20.8	$ 12.0	$ 8.8	73.3%
Production and ad valorem taxes	16.3	11.7	4.6	39.3%
Exploration expenses	10.0	3.2	6.8	212.5%
Depreciation, depletion and amortization	50.5	30.8	19.7	64.0%
General and administrative	22.4	14.5	7.9	54.5%
Operating expenses	$ 120.0	$ 72.2	$ 47.8	66.2%

	Year Ended December 31,			
	2008	2007	Change	Percent Change

Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 1.08	$ 0.91	$ 0.17	18.7%
Production and ad valorem taxes	$ 0.85	$ 0.88	$ (0.03)	−3.4%
Exploration expenses	$ 0.52	$ 0.24	$ 0.28	116.7%
Depreciation, depletion and amortization	$ 2.63	$ 2.33	$ 0.30	12.9%
General and administrative expenses	$ 1.17	$ 1.10	$ 0.07	6.4%

Lease Operating Expenses. Lease operating expenses for 2008 were $20.8 million, compared to $12.0 million in 2007. The increase in lease operating expenses was primarily due to the addition of the STGC Properties and the South Texas properties from the Smith acquisition, increased workovers and general increases in the costs of goods and services in the industry.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2008 were $16.3 million, compared to $11.7 million in 2007. The increase in production and ad valorem tax expenses was primarily due to higher production and realized prices in 2008.

Exploration Expenses. Total exploration expenses were $10.0 million in 2008 compared to $3.2 million in 2007. The significant increase in exploration expenses was primarily due to the release and abandonment of the undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas in 2006 which resulted in leasehold abandonment cost of $7.1 million in 2008.

Depreciation, Depletion and Amortization. DD&A expense for 2008 was $50.5 million compared to $30.8 million in 2007, as a result of higher production volumes and a higher DD&A rate.

Impairment of Oil and Gas Properties. Impairment expense for 2008 was $36.0 million compared to $4.4 million in 2007. In December 2008, we recorded a non-cash impairment expense of $10.2 million, primarily related to our Grand Lake Field in Southwest Louisiana, resulting from negative reserve revisions related to low commodity prices at year end. In September 2008, we recorded a non-cash impairment expense of $25.8 million related to the abandonment of the Rodessa formation development in our Madisonville Field in our Southeast Texas Region.

General and Administrative Expenses. Our G&A expenses were $22.4 million for 2008 compared to $14.5 million in 2007. Included in G&A expense is a non-cash stock expense of $5.4 million ($0.28 per Mcfe) and $4.7 million ($0.36 per Mcfe) for 2008 and 2007, respectively. G&A expenses increased primarily due to higher personnel costs, higher professional fees and higher office rent expense related to expanding our infrastructure.

Gain on Sale of Assets. Gain on the sale of assets for 2008 was $15.2 million. The net gain on the sale of assets was primarily due to the disposition of our interest in the Barnett Shale Play in the first quarter 2008, which resulted in a gain of $15.6 million. The gain on the sale of assets in 2007 was $0.7 million.

Interest Expense. Interest expense was $21.1 million for 2008, up from $14.9 million in 2007. Total interest expense increased primarily as a result of higher outstanding loan balances on our credit agreements related to our acquisition and drilling activity. Total interest expense capitalized for 2008 and 2007 was $0.9 million and $1.3 million, respectively.

Other Financing Costs. Other financing costs were $1.5 million for 2008 compared with $1.3 million for 2007. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and to commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swaps. This non-cash unrealized gain for 2008 was $49.4 million compared with a non-cash unrealized loss of $18.2 million for 2007. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges, and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net income before taxes was $72.9 million for 2008 compared to a net loss before taxes of $0.8 million in 2007. After adjusting for permanent tax differences, we recorded income tax expense of $26.7 million for 2008, of which $0.6 million was current tax expense and $26.1 million was deferred. The income tax benefit of $0.4 million for 2007 was all deferred.

Dividends on Preferred Stock. Dividends on preferred stock were $4.2 million for 2008 compared with $4.5 million in 2007. Dividends in 2008 included $4.1 million on the Series G Preferred Stock and $0.1 million on the Series H

Preferred Stock. Dividends in 2007 included $4.3 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.1 million on the Series E

Preferred Stock. All of the Series E Preferred Stock was converted to shares of our common stock in May 2007.

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

Revenues

	Year Ended December 31,			
	2007	2006	Change	Percent Change
	(In millions, except percentages)			
Revenues:				
Natural gas sales	$ 67.9	$ 10.6	$ 57.3	540.6%
Crude oil sales	27.0	10.9	16.1	147.7%
Natural gas liquids sales	14.3		14.3	%
Total operating revenues	$ 109.2	$ 21.5	$ 87.7	407.9%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, increased by 407.9%, to $109.2 million in 2007 compared to $21.5 million in 2006. The increase in net revenues was primarily due to the effect of the STGC Properties acquisition in May 2007, which significantly increased our production volumes.

	Year Ended December 31,			
	2007	2006	Change	Percent Change
Sales (production) volumes:				
Natural gas (Mcf)	9,067,777	1,542,423	7,525,354	487.9%
Crude oil (Bbl)	408,864	184,881	223,983	121.1%
Natural gas liquids (Bbl)	285,907		285,907	%
Natural gas equivalents (Mcfe)	13,236,403	2,651,709	10,584,694	399.2%

For 2007, sales volumes increased approximately 400% compared to production in 2006. On a daily basis we produced an average of 36.3 MMcfe/d in 2007 compared to an average of 7.3 MMcfe/d in 2006.

	Year Ended December 31,			
	2007	2006	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 6.78	$ 6.76	$ 0.02	0.3%
Crude oil (Bbl)	74.38	63.29	11.09	17.5%

Natural gas liquids (Bbl)	49.92		49.92	%
Natural gas equivalents (Mcfe)	8.02	8.34	(0.32)	−3.8%
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 7.48	$ 6.85	$ 0.63	9.2%
Crude oil (Bbl)	66.09	59.00	7.09	12.0%
Natural gas liquids (Bbl)	49.92		49.92	%
Natural gas equivalents (Mcfe)	8.25	8.10	0.15	1.9%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. No natural gas liquids were sold in 2006. We realized a loss of $3.4 million on our crude oil hedges and a gain of $6.4 million on our natural gas hedges in 2007 compared to a realized loss of $0.8 million for crude oil hedges and a realized gain of $0.2 million for natural gas hedges in 2006.

Operating Overhead and Other Income. Revenues from working interest partners increased to $0.4 million in 2007 compared to $0.2 million in 2006 due to the increase in administrative overhead fees charged to partners on the operated acquired STGC Properties.

Costs and Expenses

	Year Ended December 31,			
	2007	2006	Change	Percent Change
	(In millions, except percentages)			
Operating Expenses:				
Lease operating expenses	$ 12.0	$ 5.6	$ 6.4	114.3%
Production and ad valorem taxes	11.7	1.9	9.8	515.8%
Exploration expenses	3.2	0.7	2.5	357.1%
Depreciation, depletion and amortization	30.8	4.0	26.8	670.0%
General and administrative expenses	14.5	8.7	5.8	66.7%
Total operating expenses	$ 72.2	$ 20.9	$ 51.3	245.5%

	Year Ended December 31,			
	2007	2006	Change	Percent Change
Selected Costs ($ per Mcfe):				
Lease operating expenses	$ 0.91	$ 2.12	$ (1.21)	−57.1%
Production and ad valorem taxes	$ 0.88	$ 0.71	$ 0.17	23.9%
Exploration expenses	$ 0.24	$ 0.25	$ (0.01)	−4.0%
Depreciation, depletion and amortization	$ 2.33	$ 1.52	$ 0.81	53.3%
General and administrative expenses	$ 1.10	$ 3.29	$ (2.19)	−66.6%

Lease Operating Expenses. Lease operating expenses for 2007 were $12.0 million, compared to $5.6 million in 2006. The increase was primarily due to the addition of the STGC Properties.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2007 were $11.7 million, compared to $1.9 million in 2006. The increase in production and ad valorem tax expenses was primarily due to the significant increase in production related to the acquisition of the STGC Properties.

Exploration Expenses. Total exploration expenses were $3.2 million in 2007 compared to $0.7 million in 2006. Exploration expenses increased primarily as a result of the acquisition of the STGC Properties.

Depreciation, Depletion and Amortization. DD&A expense for 2007 was $30.8 million compared to $4.0 million in 2006, as a result of our acquisition of the STGC Properties.

Impairment of Oil and Gas Properties. Impairment expense was $4.4 million in 2007, primarily related to impairments on our Turkey Creek and Huff McFaddin properties, and $3.1 million in 2006, primarily related to our Iola property. Declining performance and lower gas prices at year end were contributing factors in these property impairments.

General and Administrative Expenses. Our G&A expenses were $14.5 million in 2007 compared to $8.7 million in 2006. Included in G&A expense is non-cash stock expense of $4.7 million ($0.36 per Mcfe) and $3.8 million ($1.44 per Mcfe) for 2007 and 2006, respectively. The $5.8 million increase was primarily due to higher personnel costs, information technology costs, professional fees and office rent incurred in expanding our infrastructure after the acquisition of the STGC Properties.

Interest Expense. Interest expense was $14.9 million in 2007, up from $0.1 million in 2006. Total interest increased to $16.2 million for 2007 because of the higher outstanding balances on our credit agreements related to the STGC Properties acquisition. However, $1.3 million of that interest, which was related to our Madisonville/Rodessa Prospect, was capitalized in 2007.

Other Financing Costs. Other financing costs were $1.3 million in 2007 compared with $0.2 million in 2006. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and to commitment fees related to the unused portion of the credit agreements.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swap. This non-cash unrealized loss for 2007 was $18.2 million compared with a non-cash unrealized gain of $6.1 million for 2006. This amount will vary period to period and will be a function of the hedges in place, the strike prices of those hedges and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $0.8 million in 2007 compared to net income before taxes of $3.3 million in 2006. After adjusting for permanent tax differences, we recorded an income tax benefit of $0.4 million in 2007 and an income tax expense of $1.4 million in 2006. The income tax benefit/expense was all deferred for both years.

Dividends on Preferred Stock. Dividends on preferred stock were $4.5 million in 2007 compared with $3.6 million for 2006. Dividends in 2007 included $4.3 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.1 million on the Series E Preferred Stock. Dividends in 2006 included $3.2 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.3 million on the Series E Preferred Stock. All of the Series E Preferred Stock was converted to common stock in May 2007.

Prior to the third quarter of 2007, we accumulated undeclared dividends on the Series G Preferred Stock, on a simple or non-compounded basis. During the third quarter, we were notified by the holder of a majority of our outstanding Series G Preferred Stock, Oaktree Holdings, that it believed that the provisions of the Certificate of Designations for the Series G Preferred Stock required compounding dividends. After reviewing its interpretation, and consulting with legal counsel, we and the Oaktree Holdings settled the dispute and agreed to calculate the accrued, undeclared and unpaid dividends on a compounded basis. This new basis for calculating the dividend accrual was documented in a clarification memo between the parties. The change in the method of calculating the accrued, undeclared dividend was a change in accounting estimate necessitated by the new information that became available with the written agreement between the parties in the settlement of the dispute. The net effect of the change in the accounting estimate was an increase of $0.7 million in preferred stock dividends in the Consolidated Statements of Operations for the year ended December 31, 2007, of which approximately $0.4 million was related to prior years, and $0.1 million and $0.2 million was related to the first and second quarters of 2007, respectively.

Critical Accounting Policies

The discussion and analysis of financial condition and results of our operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate such estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of the more significant accounting policies, estimates and judgments. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of our financial statements. Please read the notes to our audited consolidated financial statements included in this prospectus for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

Depletion and Depreciation

We consider depletion and depreciation of oil and gas properties and related support equipment to be critical accounting estimates, based upon estimates of total recoverable natural gas, crude oil and natural gas liquids reserves. The estimates of natural gas, crude oil and natural gas liquids reserves utilized in the calculation of depletion and depreciation are estimated in accordance with guidelines established by the Society of Petroleum Engineers, the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end, except by contractual arrangements. We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized natural gas, crude oil and natural gas liquids costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that the estimates of future cash inflows, future gross revenues, the amount of natural gas, crude oil and natural gas liquids reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Impairments

We assess all of our properties for possible impairment on an annual basis as a minimum, or as circumstances warrant, based on geological trend analysis, changes in proved reserves or relinquishment of acreage. When impairment occurs, the adjustment is recorded to accumulated depletion. See discussion of impairment expenses in Management s Discussion and Analysis of Financial Condition and Results of Operations.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our natural gas, crude oil and natural gas liquids wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which our asset retirement obligation, or ARO, is incurred. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserves estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to acquisitions, changes in estimates of plugging and abandonment costs, changes in the risk-free rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs.

Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments.

Recent Accounting Pronouncements

SEC 33-8995/34-59192. In December 2008, the SEC adopted Release No. 33-8995/34-59192, Modernization of Oil and Gas Reporting (SEC 33-8995). This release amends the oil and gas reporting disclosures that exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934 to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The new rules include changes for the pricing used to estimate reserves; permitting disclosure of possible and probable reserves; permitting the inclusion of non-traditional resources in reserves and the use of new technology for determining reserves. SEC 33-8995 is effective for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently evaluating the provisions of SEC 33-8995 and assessing the affect its adoption will have on our financial reporting disclosures.

Contractual Obligations

The following table sets forth certain of our contractual obligations as of December 31, 2008:

	Long-Term Debt	Interest	Operating Leases	Asset Retirements	Executive Compensation	ACS Topic 740[(1)]
2009	$ 90,368	$ 14,848,716	$ 2,641,835	$ 1,659,371	$ 1,516,300	$
2010	17,352	14,848,716	1,820,471	1,031,755	1,516,300	
2011	126,673,074	5,279,543	1,437,749	1,953,292	710,000	
2012	150,000,000	3,864,088	1,419,933	438,172		
2013			1,419,933	393,668		
Thereafter			118,328	7,592,284		
Total	$ 276,780,794	$ 38,841,063	$ 8,858,249	$ 13,068,542	$ 3,742,600	$ 518,219

(1) FASB ACS Topic 740 (previously reported as FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, An interpretation of FASB Statement No. 109). We cannot predict at this time when this obligation may be required to be paid, if at all.

As of September 30, 2009, there had been no significant changes to our contractual obligations from December 31, 2008.

Liquidity and Capital Resources

Our primary cash requirements are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations, net of the realized effect of our hedging agreements, and amounts available to be drawn under our credit agreements. To the extent our cash requirements exceed our sources of liquidity, we will be required to fund our cash requirements through other means, such as through debt and equity financing activities and/or asset monetizations, and/or curtail capital expenditures.

Liquidity and cash flow

During the last year there has been volatility and disruption in the equity and debt markets. The volatility and disruptions have created conditions and/or business strategies that have adversely affected the financial condition of some of our lenders, the counterparties to our derivative instruments, our insurers and our crude oil and natural gas purchasers. While in recent months market conditions have stabilized, continued economic uncertainty may limit our ability to access the equity and debt markets. In addition, though a substantial portion of our production is hedged, we are still subject to commodity price risk and our liquidity may be adversely affected if commodity prices were to decline.

Our working capital deficit was $11.9 million as of September 30, 2009, compared to a working capital deficit of $37.6 million as of December 31, 2008. Current assets decreased $16.8 million, primarily due to the decrease in accounts receivable related to lower revenues and the decrease in the mark to market value of our current net derivatives. Current liabilities, primarily accounts payable and accrued liabilities, decreased $42.6 million due to our reduced capital expenditure activity for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008.

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the past three years and the periods ended September 30, 2009 and September 30, 2008.

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	**2007**	**2006**	**2009**	**2008**
			(In millions)		
Financial Measures					
Net cash provided by operating activities	$ 143.8	$ 69.6	$ 14.3	$ 2.8	$ 96.9
Net cash used in investing activities	(165.4)	(311.8)	(21.8)	(16.0)	(105.7)
Net cash provided by financing activities	16.7	247.0	7.0	13.3	14.3
Cash and cash equivalents		4.9			10.4
Capital expenditures, including acquisitions	200.3	312.5	21.8	16.1	140.6

Net cash provided by operating activities was $2.8 million for the nine months ended September 30, 2009, compared to $96.9 million for the nine months ended September 30, 2008, a change resulting primarily from the reduction in revenues, accounts payable and accrued liabilities as well as the change in the mark to market value of our derivatives during the nine months ended September 30, 2009. During the first nine months of 2009, the net cash provided by operating activities, before changes in working capital, was $36.4 million. Net cash provided by operating activities, before changes in working capital, was $89.3 million for the first nine months of 2008.

Net cash used in investing activities was $16.0 million for the nine months ended September 30, 2009 compared to $105.7 million for the nine months ended September 30, 2008. Net cash used for investing activities during the nine months ended September 30, 2009 were primarily capital expenditures for the development or maintenance of our proved reserves and the development of our Haynesville Shale natural gas resource play in East Texas. Net cash used in investing activities during the first nine months of 2008 was primarily for the Smith acquisition and capital expenditures for the development of our Southeast Texas properties, offset primarily by proceeds from the sale of our interest in the Barnett Shale Play.

Net cash provided by financing activities was $13.3 million for the first nine months of 2009 compared to $14.3 million for the first nine months of 2008. Net cash provided by financing activities during the first nine months of 2009 was primarily the result of net borrowings under our revolving credit facility to satisfy the fourth quarter 2008 balance in current liabilities related to our active drilling program in 2008. Net cash provided by financing activities for the first nine months of 2008 was primarily the result of borrowings on debt to fund the Smith acquisition and normal drilling expenditures, offset by repayments of debt from proceeds from the sale of our interest in the Barnett Shale Play and internally generated cash flow from operations.

Net cash provided by operating activities was $143.8 million for the year ended December 31, 2008, compared to $69.6 million for the year ended December 31, 2007, a change resulting primarily from an increase in revenues, accounts payable and accrued liabilities and a decrease in accounts receivable trade. Net cash provided by operating activities was $69.6 million for the year ended December 31, 2007, compared to $14.3 million for the year ended December 31, 2006, a change resulting primarily from an increase in revenues, accounts payable and accrued liabilities offset by an increase in accounts receivable trade.

Net cash used in investing activities was $165.4 million for the year ended December 31, 2008 compared to $311.8 million for the year ended December 31, 2007. Net cash used for investing activities during the year ended December 31, 2008 were primarily related to capital expenditures for the development or maintenance of our proved reserves, prospect acquisitions in Sabine and San Augustine counties in Texas, and the acquisition of properties in South Texas from Smith, offset in part by the sale of properties in the Barnett Shale. Net cash used in investing activities during the year ended December 31, 2007, related primarily to the acquisition of the STGC Properties and capital expenditures for the development or maintenance of our proved reserves.

Net cash provided by financing activities was $16.7 million for the year ended December 31, 2008 compared to $247.0 million for the year ended December 31, 2007. Net cash provided by financing activities during the year ended December 31, 2008 was the result of net borrowings under our revolving credit facility primarily used for our capital expenditures for the development of new reserves, for prospect acquisitions and to satisfy the South Texas acquisition from Smith, offset by cash proceeds received from the sale of properties in the Barnett Shale. Net cash provided by financing activities during the year ended December 31, 2007 was primarily the result of net cash provided by our second lien credit agreement to satisfy the acquisition of the STGC Properties and net borrowings under our revolving credit facility for our capital expenditures.

Capital resources

Revolving Credit Facility. On May 8, 2007, we entered into a revolving credit facility with Wells Fargo Bank, National Association, as agent, and The Royal Bank of Scotland, plc, which amended and restated our revolving credit facility dated as of July 15, 2005, as amended. On May 8, 2007, we borrowed $122.7 million pursuant to this revolving credit facility to pay the consideration for the acquisition of the STGC Properties and to refinance certain of our existing indebtedness. On May 31, 2007, we amended and restated this facility (as amended and restated, our revolving credit facility). Our revolving credit facility provides for aggregate borrowings of up to $400.0 million for acquisitions of crude oil and gas properties and for general corporate cash requirements.

Borrowings under our revolving credit facility are subject to a borrowing base limitation based on our proved crude oil and natural gas reserves. The borrowing base under this facility is currently set at $140.0 million. The next borrowing base re-determination under our revolving credit facility is scheduled for January 1, 2010 and is subject to semi-annual redeterminations, although our lenders may elect to make one additional redetermination between scheduled redetermination dates (and have expressly reserved the right to do so between January 1, 2010 and May 1, 2010). As of November 6, 2009, we had $129.5 million in aggregate indebtedness outstanding under our revolving credit facility. Our revolving credit facility has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2011. Our revolving credit facility also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Advances under our revolving credit facility are in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender s prime rate and the Federal Funds rate plus a margin of 0.50%. The interest rate on the

Eurodollar loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR are quoted for the maturity selected. Pursuant to an amendment to our revolving credit facility, dated July 31, 2009, applicable margin was increased from between 1.25% and 2.00% to between 2.75% and 3.50%, for LIBOR loans, and from zero and 0.50% to between 1.50% and 2.00%, for base rate loans. The specific interest margin applicable is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. Eurodollar loans of one, two, three and nine months may be selected. Pursuant to that same amendment, the commitment fee payable on the unused portion of our borrowing base was increased from 0.375% to 0.50%, which fee accrues and is payable quarterly in arrears.

On November 6, 2009, we entered into a second and a third amendment to our revolving credit facility. These amendments provided, among other things, for (i) a change in the voting percentages required for certain amendments or waivers from 50.1% to 60%, and (ii) a waiver of the current ratio and the leverage ratio for the quarter ended September 30, 2009. In connection with this offering, we expect to further amend certain financial and other covenants under our revolving credit facility.

Second Lien Term Loan Agreement. On May 8, 2007, we entered into a five-year second lien term loan agreement with Credit Suisse, as agent, which provides for term loans to be made to us in a single draw in an aggregate principal amount of $150.0 million (our second lien term loan agreement). On May 8, 2007, we borrowed $150.0 million pursuant to this second lien term loan agreement to pay the consideration for the acquisition of the STGC Properties and to refinance certain existing indebtedness. Our second lien term loan agreement replaced our then existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing. Our second lien term loan agreement matures on May 8, 2012. Loans under the second lien term loan agreement bear (pursuant to a June 5, 2007 first amendment to our second lien term loan agreement) interest at a per annum rate equal to LIBOR plus 5.75%, in the case of LIBOR loans, or the base rate plus 4.75%, in the case of base rate loans. Eurodollar loans of one, two, three and six months may be selected.

On May 13, 2009, we entered into a second amendment to our second lien term loan agreement (including with an affiliate of Oaktree Holdings), which, among other things, (i) modified the leverage ratio covenant to be no greater than the leverage ratio under our revolving credit facility plus 0.25, (ii) modified the PV-10 ratio covenant to not less than 1.2x beginning with the fiscal quarter ended June 30, 2009, to not be less than 1.25x, beginning with the fiscal quarter ending December 31, 2009, and to not be less than 1.5x beginning with the fiscal quarter ending December 31, 2010 and thereafter, (iii) increased the applicable margin to 8.0% for loans bearing interest at LIBOR and 7.0% for loans bearing interest at the alternate base rate, unless we meet certain leverage and PV-10 ratios, in which case the applicable margin will be 7.0% and 6.0%, respectively, (iv) set a minimum LIBOR of 3.0%, and (v) included certain fee acreage in calculations of our borrowing base after we have granted a lien on such fee acreage.

On November 6, 2009, we entered into a third amendment and waiver to our second lien term loan agreement with lenders holding a majority of the then outstanding term loans under such agreement, which included an affiliate of Oaktree Holdings. The amendment and waiver provided, among other things, for a waiver of the leverage ratio covenant under that agreement for the quarter ended September 30, 2009.

At September 30, 2009, we were in compliance with the covenants under our revolving credit facility and second term loan agreement, with the exception of the current ratio under our revolving credit facility and the leverage ratio under both of these credit agreements. We obtained waivers of such noncompliance from our lenders under both of these credit agreements for the quarter ended September 30, 2009. However, without improvement in natural gas and crude oil prices, reduction in debt levels, improvement in production volumes and/or other measures, we may not be able to comply with certain covenants under our credit agreements for future quarters. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity

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and Capital Resources Capital resources and Future capital requirements in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 for a detailed discussion of future covenant compliance under our existing credit agreements assuming we do not complete this offering.

Our revolving credit facility and our second lien term loan agreement are secured by liens on substantially all of our assets, including the capital stock of our subsidiaries. The liens securing the obligations under our second lien term loan agreement are junior to those under our revolving credit facility. Interest is payable under our credit agreements as borrowings mature and renew.

In connection with the credit agreements, we utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil and natural gas liquids production. As of September 30, 2009, we had 13.9 MMcfe of equivalent production hedged representing 2.3 MMcfe, 7.6 MMcfe and 3.9 MMcfe of hedges in place in 2009, 2010 and 2011, respectively. Of the hedges in place through 2011, approximately 80% of the hedges are natural gas hedges and 20% are crude oil hedges. We used a series of swaps and costless collars to accomplish the hedging requirements. We also constructively fixed the base LIBOR on $200.0 million of our variable rate debt by entering into interest rate swaps at a weighted average swap price of 2.61%.

At September 30, 2009, we had $141.5 million outstanding under our revolving credit facility and $150.0 million outstanding under our second lien term loan agreement.

Promissory Notes. On November 6, 2009, we issued an unsecured promissory note in aggregate principal of $10.0 million to Wells Fargo Bank, National Association, the administrative agent and a lender under our revolving credit facility. All of the proceeds of this promissory note were used to repay indebtedness outstanding under our revolving credit facility. The indebtedness under this promissory note bears interest at a per annum rate equal to two-month LIBOR plus 2.0% and matures on January 15, 2010; provided that upon an event of default resulting from the failure to make any payment of principal or interest under this promissory note, the interest rate per annum will increase to an amount equal to the lesser of the maximum rate of interest that may be charged under applicable law and LIBOR plus 4.0% or, if the promissory note has been assigned to any person other than any affiliate of Wells Fargo Bank, National Association, LIBOR plus 15.0%. The indebtedness under this promissory note may be prepaid, from time to time, in whole or in part, without premium or penalty. Wells Fargo Bank, National Association as payee, may assign this promissory note at any time provided that the assignee expressly agrees to subordinate its rights and remedies under this promissory note to all obligations under our revolving credit. In addition to any other rights and remedies Wells Fargo Bank, National Association, as payee, may have under this promissory note, upon the occurrence and continuation of an event of default, Wells Fargo Bank, National Association may cause this promissory note to be assigned to Oaktree Holdings in full. As support for this contingent obligation to purchase this promissory note, Oaktree Holdings has deposited $10.0 million in escrow for the benefit of Wells Fargo Bank, National Association. Upon an event of default under this promissory note, on January 15, 2010, Wells Fargo Bank, National Association may, at its option, cause the note to be assigned to Oaktree Holdings and can draw upon the funds held in escrow as payment for such assignment.

As consideration for Oaktree Holdings agreement to deposit $10.0 million in escrow as described above, we issued an unsecured subordinated promissory note on November 6, 2009 in aggregate principal amount of $2.0 million to Oaktree Holdings. The indebtedness under the promissory note bears interest at a per annum rate equal to 8.0% and matures on the later of (i) November 8, 2012 and (ii) the date six months after payment in full in cash of all Obligations (as such term is defined under our credit agreements), and the termination of all commitments to extend credit under our credit facilities. The promissory note is subordinated in right of payment to the prior payment in full in cash of all obligations under our credit agreements.

Covenant compliance

Our existing credit agreements contain certain financial covenants that require us to maintain a maximum level of total debt to Adjusted EBITDAX and a minimum adjusted interest coverage ratio, in each case, on a trailing four-quarter basis. Our compliance with these covenants is tested each quarter. We believe our credit agreements are material agreements and that these financial covenants are material terms of those agreements. Non-compliance with these covenants could result in a default, and an acceleration in the repayment of amounts outstanding, under our credit agreements. If an event of default occurs and is continuing under either credit agreement, we would be precluded from, among other things, paying dividends on our common stock or making additional borrowings. As a result, we believe the information presented below regarding these financial covenants is material to investors understanding of our results of operations and financial condition. See Liquidity and Capital Resources Capital resources for a more detailed description of terms and provisions of our credit agreements.

At September 30, 2009, the financial covenants contained in our credit agreements included (a) with respect to our revolving credit facility, maintaining (i) a ratio of current assets to current liabilities of at least 1.0 to 1.0, (ii) an interest coverage ratio of Adjusted EBITDAX (defined as EBITDAX in such agreement) to cash interest expense of not less than 3.0 to 1.0 and (iii) a ratio of total debt to Adjusted EBITDAX of not greater than 2.75 to 1.00 and (b) with respect to our second lien term loan agreement, maintaining (i) a minimum leverage ratio of total debt to Adjusted EBITDAX of not greater than the leverage ratio under our revolving credit facility plus 0.25 and (ii) a ratio of the PV-10 value of our oil and gas reserves to total net debt, or PV-10 Ratio (which ratio is calculated semi-annually based on the latest reserve report), to be less than 1.2x.

As of September 30, 2009, our ratio of current assets to current liabilities was 0.71. For the four quarters ended September 30, 2009, our ratio of total debt to Adjusted EBITDAX was 3.68; our ratio of interest expense to Adjusted EBITDAX was 0.27; and our PV-10 Ratio was 3.68.

We believe the presentation of Adjusted EBITDAX is appropriate to provide additional information to investors to demonstrate our ability to comply with the financial covenants to which we are and expect to be subject. For a reconciliation of net income (loss) to Adjusted EBITDAX, see Prospectus Summary Non-GAAP Financial Measures and Reconciliations. The calculation of Adjusted EBITDAX in this prospectus is in accordance with the definitions contained in our credit agreements.

Future capital requirements

Our future natural gas, crude oil and natural gas liquids 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. We intend to grow our reserves and production by further exploiting our existing property base, through drilling opportunities identified in our new resource plays in East and South Texas and in our conventional inventory. We expect to focus much of our drilling activity over the next several years on continued development of our East Texas and South Texas resource plays while we continue the development and exploitation of our core legacy properties in the South Texas and Gulf Coast areas. We anticipate that acquisitions, including of undeveloped leasehold interests, will continue to play a significant role in our business strategy as those opportunities periodically arise from time to time. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

We believe that the proceeds from this offering and our internally generated cash flow combined with access to our revolving credit facility will be sufficient to meet the liquidity requirements necessary to fund our daily operations, planned capital development and execute on our growth strategy and debt service requirements for the next

12 months. Our ability to execute on our growth strategy will be determined, in large part, by the availability of debt and equity capital at that

time, and we continuously evaluate our financing opportunities. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as continued commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our revolving credit facility in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated, although the restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all. See Risk Factors Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements, Risk Factors Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves and Management s Discussion and Analysis of Financial Condition and Results of Operations.

Due to low commodity prices and limited access to capital markets during 2009, our capital expenditure strategy for 2009 was to keep expenditures within internally generated cash flow and to reduce debt. For the nine months ended September 30, 2009, we made capital expenditures of $16.5 million, primarily for our Liberty County and East Texas leasing and drilling programs. We currently anticipate capital expenditures to be no more than $19 million in 2009. Our 2010 capital budget is approximately $55 million, exclusive of acquisitions, of which we expect to spend approximately 76% of our budget on our East Texas and South Texas resource plays and 24% on our existing producing assets. We plan to drill 12 gross (6.0 net) wells in 2010, including 7 gross (3.0 net) wells on our East Texas resource play acreage, one gross (0.4 net) wells on our South Texas resource play acreage, and 4 gross (2.6 net) wells in Liberty County. The actual number of wells drilled and the amount of our 2010 capital expenditures will depend on market conditions, availability of capital and drilling and production results. The following table sets forth our estimated capital budget for 2010:

2010E Capital Budget	Southeast Texas	South Texas	Southwest Louisiana	Colorado and Other	East Texas	Non-Operated	Total
Capital Expenditures (in millions)	$ 13	$ 3	$	$	$ 39	$	$ 55
Gross Wells	4	1			7		12
Net Wells	2.6	0.4			3.0		6.0

Inflation and Changes in Prices

While the general level of inflation affects certain costs associated with the petroleum industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have a material effect on our operations; however, we cannot predict these fluctuations.

The following table indicates the average quarterly crude oil, natural gas and natural gas liquids prices received over the last three years. Average prices per Mcf equivalent, computed by converting crude oil production to natural gas equivalents at the rate of 6 Mcf per barrel, indicate the composite impact of changes in crude oil and natural gas prices.

	Average Prices[1]			
	Natural Gas (per Mcf)	Crude Oil (per Bbl)	Natural Gas Liquids[2] (per Bbl)	Per Equivalent Mcf
2009 year to date	$ 6.77	$ 81.46	$ 27.19	$ 7.31
2008				
First	$ 8.39	$ 78.62	$ 57.18	$ 9.39
Second	10.23	95.52	55.73	10.94
Third	9.68	92.54	63.49	10.67
Fourth	7.20	68.42	28.84	7.52
2007				
First	$ 7.07	$ 60.28	$	$ 8.33
Second	7.64	62.66	43.29	8.09
Third	7.60	66.47	45.17	8.18
Fourth	7.28	69.41	55.19	6.78
2006				
First	$ 7.71	$ 58.11	$	$ 8.63
Second	6.61	60.48		8.09
Third	6.72	60.85		8.07
Fourth	6.56	56.71		7.71

(1) Average sales price are shown net of the settled amounts of our natural gas and crude oil hedge contracts.

(2) Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC Properties in May 2007.

Quantitative and Qualitative Disclosures About Market Risk

The following market rate disclosures should be read in conjunction with the quantitative disclosures about market risk contained in this prospectus, as well as with the consolidated financial statements and notes thereto. All of our derivative financial instruments are for purposes other than trading. We only enter into derivative financial instruments in conjunction with our crude oil and natural gas price hedging activities. Hypothetical changes in interest rates and prices chosen for the following stimulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations.

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Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. To manage this risk and reduce our sensitivity to volatile interest rates, we have entered into interest rate swap agreements with a total notional amount of $200.0 million related to our indebtedness. However, these interest rate swap agreements limit the benefit of decreases in interest rates. Moreover, these swap agreements apply only to a portion of our debt and provide only partial protection against increases in interest rates. Under these agreements, we receive interest at a floating rate equal to one-month LIBOR and pay interest at a fixed rate of 1.50% for $50.0 million and pay interest at 2.90% for $150.0 million, effectively setting our base LIBOR rate at 2.6%. As of September 30, 2009, the interest rate swaps had an estimated net fair value liability of $5.2 million. Assuming our current level of borrowings and considering the effect of the interest rate swap agreements, a 100 basis point increase in the interest rate we pay under our revolving credit facility would not have had a material impact on our interest expense for the nine months ended September 30, 2009.

Commodity Price Risk

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our natural gas, crude oil and natural gas liquids production to reduce our sensitivity to volatile commodity prices. During 2009, 2008 and 2007, we entered into price swaps and put agreements with financial institutions. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to price fluctuations. However, derivative arrangements limit the benefit to us of increases in the prices of crude oil and natural gas sales. Moreover, our derivative arrangements apply only to a portion of our production and provide only partial price protection against declines in price. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our price hedging program in light of increases in production, market conditions, commodity price forecasts, and capital spending and debt service requirements.

Counterparty Risk

We have exposure to financial institutions in the form of derivative transactions in connection with our hedges. These transactions are with counterparties in the financial services industry, specifically with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparties. We believe our counterparty risk related to our derivatives is low because of the offsetting relationships we have with each of our counterparties. In addition, we also have exposure to financial institutions within our credit agreements. If any lender under our revolving credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender s commitment under the revolving credit agreement.

Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded a net asset for derivative instruments of $34.2 million and a net liability of $15.3 million at December 31, 2008 and 2007, respectively. As a result of these agreements, we recorded a non-cash unrealized gain, for unsettled contracts, of $49.4 million, a non-cash unrealized loss of $18.2 million and a non-cash unrealized gain of $6.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. As of September 30, 2009, these derivative instruments had an estimated net fair value asset of $16.9 million. The estimated change in fair value of the derivatives is reported in Other Income (Expense) as unrealized gain (loss) on derivative instruments.

For natural gas, crude oil and natural gas liquids derivatives settled during 2008, we realized losses, reflected in operating revenues, of $9.3 million for the year ended December 31, 2008. For natural

gas, crude oil and natural gas liquids derivatives settled during 2007, we realized gains of $3.0 million for the year ended December 31, 2007 and a non-cash unrealized gain of $6.1 million for the twelve months ended December 31, 2006. For natural gas, crude oil natural gas liquids derivatives settled during 2006, we realized losses, reflected in operating revenues of $0.6 million for the twelve months ended December 31, 2006. For interest rate swaps, we realized losses, included in interest expense, of $4.0 million for the twelve months ended December 31, 2008. We realized gains, included in interest expense, of $0.2 million from interest rate swaps for the twelve months ended December 31, 2007.

For natural gas, crude oil and natural gas liquids derivatives settled during the nine months ended September 30, 2009 and 2008, reflected in operating revenues, we realized gains of $30.8 million and losses of $13.2 million, respectively. We also recorded a non-cash unrealized loss, reflected in other income (expense), of $17.7 million for the nine months ended September 30, 2009 and a non-cash unrealized gain of $0.8 million for the nine months ended September 30, 2008. For interest rate swaps, we realized a loss, included in interest expense, of $3.2 million and $2.8 million for the nine months ended September 30, 2009 and 2008, respectively. We also recorded for interest rate swaps non-cash gains, reflected in other income (expense), of $0.4 million and $0.9 million for the nine months ended September 30, 2009 and 2008, respectively.

The following commodity derivatives contracts were in place at September 30, 2009.

Crude Oil		**Volume/Month**		**Price/Unit**
Oct 2009-Dec 2009	Swap	5,200 Bbls	$	74.20
Oct 2009-Dec 2009	Collar	12,800 Bbls	$	66.55-$71.40
Oct 2009-Dec 2009	Collar	10,733 Bbls(1)	$	115.00-$171.50
Jan 2010-Dec 2010	Swap	4,250 Bbls	$	72.32
Jan 2010-Dec 2010	Collar	9,000 Bbls	$	65.28-$70.60
Jan 2010-Dec 2010	Collar	7,604 Bbls(1)	$	110.00-$181.25
Jan 2011-Dec 2011	Swap	3,300 Bbls	$	70.74
Jan 2011-Dec 2011	Collar	7,000 Bbls	$	64.50-$69.50
Natural Gas				
Oct 2009-Dec 2009	Swap	36,000 MMbtu	$	8.32
Oct 2009-Dec 2009	Collar	475,000 MMbtu	$	7.90-$9.45
Oct 2009-Dec 2009	Collar	101,200 MMbtu(1)	$	9.50-$18.70
Jan 2010-Jun 2010	Swap	45,833 MMbtu(1)	$	6.25(2)
Jan 2010-Dec 2010	Swap	29,000 MMbtu	$	7.88
Jan 2010-Dec 2010	Collar	351,000 MMbtu	$	7.57-$9.05
Jan 2010-Dec 2010	Collar	85,167 MMbtu(1)	$	9.00-$15.25
Jan 2011-Dec 2011	Collar	266,000 MMbtu	$	7.32-$8.70

Interest Rate		**Notional Amount**	**Fixed LIBOR Rate**
Oct 2009-Dec 2010	Swap	$ 50,000,000	1.50%
Oct 2009-May 2011	Swap	$150,000,000	2.90%

(1) Average volume per month for the remaining contract term.

(2) Average price for the contract term.

The total net fair value asset for derivative instruments at September 30, 2009 was approximately $16.9 million and at December 31, 2008 was approximately $34.2 million, which are shown as derivative instruments on the balance sheet.

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BUSINESS

Company Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

In late 2008 and early 2009, we acquired approximately 12,000 net acres in East Texas where we completed our first well, the Kardell #1H, in October 2009. This well targeted the Haynesville Shale and initially produced 30.7 MMcfe/d, which we believe to be the highest publicly announced initial production rate to date in that formation. In addition to the Haynesville Shale, we believe this acreage is equally prospective in the Bossier Shale and James Lime formations where industry participants have drilled successful wells on adjacent acreage.

In 2007, we acquired approximately 2,800 net acres in South Texas, which we believe is prospective in the Austin Chalk and the Eagle Ford Shale. We drilled our first well on this acreage, the Dubose #1, during the fourth quarter of 2009, and we are preparing to complete the well in the Eagle Ford Shale.

We intend to grow reserves and production by continuing to develop our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of over 800 drilling locations associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 34 gross (15.2 net) wells with an overall success rate of 91% (excluding one well which has not yet been completed).

As of December 31, 2008, our estimated proved reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., were 131.9 Bcfe, consisting of 96.2 Bcf of natural gas and 6.0 MMBbl of crude oil, condensate and natural gas liquids. As of December 31, 2008, 73% of our proved reserves were natural gas, 69% were proved developed and 81% were attributed to wells and properties operated by us. From 2006 to 2008, we grew our estimated proved reserves from 46.4 Bcfe to 131.9 Bcfe. In addition, we grew our average daily production from 7.3 MMcfe/d for the year ended December 31, 2006 to 43.0 MMcfe/d for the nine months ended September 30, 2009. For the nine months ended September 30, 2009, we generated $55.2 million of Adjusted EBITDAX. Our definition of the non-GAAP financial measure of Adjusted EBITDAX and a reconciliation of net income (loss) to Adjusted EBITDAX are provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations. For the same period, our net income (loss) was $(16.8) million.

Our areas of primary focus include the following:

> *East Texas.* Our East Texas properties includes approximately 17,000 gross (12,000 net) acres acquired in 2008 and early 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, where we will focus primarily on the pursuit of the Haynesville Shale, Bossier Shale and James Lime formations. In October 2009, we drilled and completed our first well in this area, the Kardell #1H. While drilling this well, we identified additional prospective formations, including the Pettet and Knowles Lime.

Southeast Texas. Our Southeast Texas properties primarily include the Felicia field area in Liberty County. We own approximately 27,300 gross (15,100 net) acres in Liberty, Madison and Grimes Counties. As of September 30, 2009, we owned and operated 35 gross (27.0 net) producing wells, representing approximately 38% of our average daily production for the first nine months of 2009.

South Texas. Our South Texas properties include approximately 2,800 gross (2,800 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and Eagle Ford Shale. Our conventional operations include approximately 87,600 gross (50,700 net) acres predominantly in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties.

We also own interests in the following areas:

Southwest Louisiana. Our Southwest Louisiana properties include approximately 8,200 gross (3,600 net) acres, primarily in the Fenton field area of Calcasieu Parish and our legacy Grand Lake and Lacassine fields in Cameron Parish. In addition, we own a 15% working interest ownership in 2007 exploratory successes in Louisiana at Sabine Lake and West Cameron 432.

Colorado and Other. Our Colorado and other properties include primarily producing assets and approximately 16,900 gross (11,900 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams County) and a minor crude oil property in Mississippi.

The following table sets forth certain information with respect to our estimated proved reserves as of December 31, 2008, as estimated by Netherland, Sewell & Associates, Inc., and production and net acreage for the nine months ended September 30, 2009. The following table also identifies potential drilling locations and net acreage as of September 30, 2009:

	Proved Reserves					
Region	**Estimated Proved Reserves as of December 31, 2008 (MMcfe)**	**% Natural Gas**	**% Proved Developed**	**Average Daily Production for the Nine Months Ended September 30, 2009 (Mcfe/d)**	**Net acreage at September 30, 2009**	**Identified Potential Gross Drilling Locations at September 30, 2009[1]**
Southeast Texas	29,393	60.1%	85.8%	16,521	15,100	26
South Texas	60,602	78.0%	59.8%	11,963	53,500	124
Southwest Louisiana	10,398	62.4%	57.3%	3,139	3,600	4
Colorado and Other	6,675	71.5%	55.3%	539	11,900	164
East Texas[2]					12,000	422
Non-operated[3]	24,879	80.2%	79.8%	10,817		82
Total	131,947	72.9%	68.9%	42,979	96,100	822

(1) Includes multiple drilling locations on acreage with multiple target formations.

(2) We recently completed our first well on our East Texas acreage, the Kardell #1H, as a horizontal Haynesville Shale producer, in which we own a 52% working interest. Drilling locations in this region were identified assuming an allocated 100 acres per potential horizontal East Texas well drilled to multiple target formations.

(3) Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% and 15% respective working interests resulting from exploratory successes in 2007 at Sabine Lake and West Cameron 432, in Southwest Louisiana.

We have significantly increased our proved reserves and production through acquisitions and drilling since our recapitalization in early 2005. In 2007, we tripled our reserve size through the acquisition from EXCO of producing properties in the South Texas, Southeast Texas and Southwest Louisiana regions, adding an aggregate of approximately 95 Bcfe to our net proved reserves at a cost of $2.50 per Mcfe of proved reserves as of the effective date. We added 21 Bcfe to our South Texas proved reserves through the Smith acquisition in 2008 at an average cost of $2.82 per Mcfe of proved reserves as of the closing date. Our acquisitions are focused on areas in which we can leverage our geographic and geological expertise to exploit those drilling opportunities identified at the time of the acquisition and develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves. We intend to continue to pursue the acquisition of assets in our core areas, to continue to selectively expand our presence in our East Texas resource play and to continue to develop exploratory opportunities through our internal prospect generation team.

We have also been successful at adding reserves through the drilling of non-proved targets through our exploitation program on existing producing properties. Since January 2008, we have drilled 34 gross wells (16 operated and 18 non-operated), with an overall success rate of 91% (excluding one well which has not yet been completed). We added approximately 18.4 Bcfe in proved reserves in 2008. We believe that we have a current inventory of 822 identified drilling opportunities on our producing asset base as noted in the table above.

During the latter half of 2008 and early 2009, we acquired approximately 12,000 net acres in San Augustine and Sabine Counties in East Texas, which we believed to be prospective in the Haynesville Shale, James Lime and Mid-Bossier formations. We have identified over 422 drilling locations on our acreage targeting these formations alone. Recent activity in the area also indicates that the Pettet and Knowles Lime formations also appear prospective. We have separated our acreage into several joint development areas (JDAs) of varying sizes and are working with other industry players holding acreage positions in those areas to jointly develop our positions. Our Bruin prospect, on which our first well, the Kardell #1H was drilled, is one such JDA. We and Devon Energy Corporation, the operator, each contributed approximately 350 acres to the JDA in San Augustine County and drilled the Kardell #1H well. Given the success we have had on the Kardell #1H well, we will likely allocate a large portion of our drilling capital budget to develop this resource play further for the next several years.

Strategy

The key elements of our business strategy are:

Develop our East Texas resource play. We have approximately 12,000 net acres in San Augustine and Sabine Counties of East Texas, which we believe is prospective in the Haynesville Shale, Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H. The well tested at 30.7 MMcfe/d, which we believe to be the highest publicly reported 24-hour initial production rate for a Haynesville Shale well in Texas or Louisiana and is currently flowing to sales. We believe the Kardell #1H confirms the potential of our Bruin Prospect, which is comprised of 3,000 net acres in San Augustine County, resulting in over 100 potential drilling locations in multiple formations. We are currently in the planning stages of several wells in this area and intend to further evaluate and exploit these multiple formations beginning in early 2010. We have an additional 9,000 net acres outside this prospect within Sabine and San Augustine Counties, and we expect to drill our initial well on that acreage in early 2010. We intend to allocate a substantial portion of our capital budget over the next several years to develop the significant potential that we believe exists on our East Texas acreage. Based on our current capital budget, we expect to drill approximately 7 gross (3.0 net) wells in 2010 that will target the Haynesville and Bossier Shales, while retaining future development opportunities in shallower formations.

Develop our South Texas resource play. We have approximately 2,800 net acres in Bee County, Texas which we believe is prospective in the Austin Chalk and Eagle Ford Shale. In November 2009, we drilled our initial well on this acreage, the Dubose #1. This well is in the process of being completed with results expected prior to year end 2009. We intend to

allocate a portion of our capital budget in 2010 to validate the potential we believe exists on our acreage.

Exploit our existing producing property base to generate cash flows. We believe our multi-year drilling inventory of high return exploitation opportunities on our existing producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a larger portion of our resource plays and exploration activities from cash flows from operations. In 2010, we intend to focus much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which industry players have recently experienced success on wells in the area. We own 3D seismic data that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. We have drilled 11 gross (6.8 net) wells in Liberty County since early 2008 and have successfully completed 82%. During 2010, we intend to drill 4 gross (2.6 net) wells in this area.

Explore in defined producing trends. Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

Make opportunistic acquisitions that meet our strategic and financial objectives. We seek to acquire natural gas and crude oil properties, including both undeveloped and producing reserves in areas where we have specific operating expertise.

Reduce commodity exposure through hedging. We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. As of September 30, 2009, we had 13.9 Bcfe of equivalent production hedged, representing 1.8 Bcf, 6.1 Bcf and 3.2 Bcf of natural gas hedges in place and 86 MBbl, 250 MBbl and 124 MBbl of crude oil hedges in place for the fourth quarter of 2009, the year 2010 and the year 2011, respectively. The average price of our natural gas and crude oil hedges in place is $8.19/MMBtu and $86.03/Bbl for the fourth quarter of 2009, $7.71/MMBtu and $83.02/Bbl in the year 2010 and $7.32/MMBtu and $66.50/Bbl in the year 2011.

Competitive Strengths

Our competitive strengths include:

Geographically focused operations in basins with established production profiles. The geographic concentration of our current operations along the onshore Texas Gulf Coast and in South Texas allows us to establish economies of scale with respect to drilling, production, operating and administrative costs, and enables us to leverage our base of technical expertise in these geographic areas. In addition, we believe the cash flows from our existing properties provide a stable foundation to support our ongoing exploitation and development efforts.

Significant operational control. As of September 30, 2009, we operated a majority of our producing wells. As a result, we exercise a significant level of control over the amount and timing of expenses, capital allocation and other aspects of development, exploitation and exploration. While operatorship of future wells on our East Texas acreage will be subject to negotiation as drilling units are formed, we expect to operate a significant number of the wells we drill on this acreage.

Proven track record of reserve and production growth. Since 2005, we have significantly grown proved reserves and production through a combination of continued drilling success and the successful acquisition of underdeveloped properties that have proven to be complementary to our existing asset base and technical expertise. We plan to continue this growth by focusing on a balanced combination of drilling longer life, multi-pay natural gas targets within our resource plays and exploitation of our producing properties and undeveloped acreage.

Large inventory of identified projects. We currently have an inventory of over 800 identified potential drilling locations, including 375 associated with our existing conventional properties, plus an estimated 422 locations on our East Texas resource play acreage and an estimated 25 locations on our South Texas resource play acreage. Since the beginning of 2008, we have drilled 16 gross (10.7 net) operated and 18 gross (4.5 net) non-operated wells and have experienced a 91% success rate (excluding one well which has not yet been completed). We expect to drill 12 gross (6.0 net) wells in 2010.

Experienced management and technical teams. Our senior management team averages over 25 years of experience in the energy industry and is led by Allan D. Keel, President and Chief Executive Officer, who has 25 years of experience in the oil and natural gas industry. Mr. E. Joseph Grady, our Senior Vice President and Chief Financial Officer, has over 30 years of financial management experience in the energy industry. Other members of our senior management include: Mr. Tracy Price, our Senior Vice President Land Business/Development; Mr. Thomas H. Atkins, our Senior Vice President Exploration; and Mr. Jay S. Mengle, our Senior Vice President Engineering, each of whom has more than 25 years of experience in the oil and gas industry. Our experienced management team has an established track record of successfully exploiting and developing natural gas and crude oil properties.

Properties

As of September 30, 2009, we operated a majority of our producing wells and held an average 52% (75% operated and 25% non-operated) working interest. Gross wells are the total wells in which we own a working interest. Net wells are the sum of the fractional working interests we own in gross wells. Our estimated net proved reserves were approximately 2.6 MMBbls of crude oil and condensate 96.2 Bcf of natural gas and 3.4 MMBbls of natural gas liquids at December 31, 2008. Substantially all of our properties are located onshore in Texas and Louisiana. As of December 31, 2008, our properties were located in the following regions: Southeast Texas, South Texas, Southwest Louisiana and Colorado and Other, although we separately classify our non-operated properties in our regions as Non-Operated. Given our success in 2009 with the first well on our East Texas acreage, the Kardell #1H, we intend to allocate a substantial portion of our drilling capital budget in the next several years to the development of the significant potential that we believe exists in this area.

Our estimated net proved reserves as of December 31, 2008, were approximately 72.9% natural gas, 15.4% natural gas liquids and 11.7% crude oil and condensate. As of December 31, 2008, approximately 68.9% of total proved reserves were classified as proved developed. The average remaining proved developed producing reserves per net operated well at December 31, 2008 was 356.4 MMcfe. Our estimated net proved reserves at December 31, 2008 had estimated PV-10 of $291.0 million.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 8.4 years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, 15 gross (10.3 net) operated wells and 17 gross (4.0 net) non-operated wells were drilled, 93% and 88% respectively of which were successes. During the nine months ended September 30, 2009, we drilled one gross (0.4 net) operated well, which has not yet been evaluated. We also drilled one gross (0.5 net) non-operated well in our East Texas acreage, which was a success. In 2010, we currently expect to drill 12 gross (6.0 net) wells. Also, as of September 30, 2009, we had identified 66 proved undeveloped drilling locations and 756 other drilling locations.

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Operated Properties

East Texas

East Texas includes 17,000 gross (12,000 net) acres acquired in the latter half of 2008 and early 2009 in the highly prospective and active resource play in San Augustine and Sabine Counties, in which we will focus primarily on the pursuit of the Haynesville Shale, Bossier Shale and James Lime formations. Other potential formations that were seen in our Kardell #1H well (a non-operated well), and that are believed to be prospective in the area, are the Pettet and Knowles Lime. In the past year, the Haynesville Shale formation has become one of the most active natural gas plays in the United States, primarily in Northern Louisiana and East Texas. The formation is as much as 300 feet thick and exists at depths ranging from 10,500 to more than 15,000 feet. The Haynesville Shale has proven productive across numerous parishes in Northwest Louisiana and counties in East Texas, primarily Harrison, Panola and Shelby. We have identified 422 drilling locations in this area, based on 100-acre spacing. We are actively pursuing joint venture opportunities with third parties to develop our Haynesville Shale acreage in Texas. While operatorship of future wells on our East Texas acreage will be subject to negotiation as drilling units are formed, we expect to operate a significant number of the wells we drill on this acreage.

Southeast Texas

Our Southeast Texas properties consist primarily of the Felicia field area in Liberty County, Texas, which we acquired in the EXCO acquisition. We believe that the Liberty County area will continue to provide accelerated production and high rates of return as we exploit our probable and possible opportunities targeting the Yegua and Cook Mountain formations. We currently plan to drill or sidetrack 4 gross (2.6 net) wells during 2010 in Liberty County. The Southeast Texas region also includes the Madisonville/Iola area in Madison and Grimes Counties, which has deeper Smackover potential to complement our current Yegua, Frio, Cook Mountain and Rodessa production.

As of September 30, 2009, in Southeast Texas, we owned and operated 35 gross (27.0 net) producing wells. Our operated wells have an average working interest of 75% and an average net revenue interest of 60%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 16,300 feet. We principally produce from the Frio, Yegua, Cook Mountain and Rodessa formations. We own 27,300 gross (15,100 net) acres in Southeast Texas.

The average net production from our Southeast Texas properties for the year ended December 31, 2008 was 20.6 MMcfe/d, or approximately 39% of our 2008 total net equivalent production. The average net production from our Southeast Texas properties for the nine months ended September 30, 2009 was 16.5 MMcfe/d, or approximately 38% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.8 MMcfe/d and 0.6 MMcfe/d, respectively.

Our estimated net proved reserves for our Southeast Texas properties as of December 31, 2008, were 29,393 MMcfe, of which approximately 80.3% were natural gas and natural gas liquids and 85.8% were classified as proved developed. The average remaining proved developed producing reserves per net operated well at December 31, 2008 was 672.7 MMcfe. Our estimated net proved reserves at December 31, 2008 had estimated PV-10 of $89.7 million.

Our average reserve life for this region is approximately five years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, seven gross (4.9 net) wells were drilled on our Southeast Texas properties, 86% of which were successes, and during the nine months ended September 30, 2009, we drilled two gross (1.3 net) wells in Southeast Texas, of which both were successful. Also, as of September 30, 2009, we had identified five proved undeveloped drilling locations and 21 other drilling

locations on our Southeast Texas leasehold acreage. Our drilling opportunities for Southeast Texas have an average estimated well life of eight years.

South Texas

Our South Texas properties consist primarily of: the Cage Ranch field in Brooks County and Southwest Speaks field in Lavaca County, both acquired in the EXCO acquisition; the North Bob West field in Zapata County and the Brushy Creek field in DeWitt County, both acquired in the Smith acquisition; and Lobo trend production and acreage in Zapata and Webb Counties. We own approximately 90,400 gross (53,500 net) acres in these known prolific trends that we intend to continue to exploit.

We also own approximately 28,000 gross (28,000 net) acres in the Edwards Trend, which we call our NW Pawnee prospect, that we believe not only contains the Edwards/Sligo formations, but also believe to be prospective in the Austin Chalk and the Eagle Ford Shale. We recently drilled and are in the process of completing, the Dubose #1 well, our first well on this acreage. If this well is successful, we plan to drill additional wells in this area during 2010.

As of September 30, 2009, in South Texas, we owned and operated 94 gross (73.0 net) producing wells. Our operated wells have an average net working interest of 73% and an average net revenue interest of 58%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 19,400 feet. We principally produce from the Wilcox, Vicksburg and Lobo formations.

The average net production from our South Texas properties for the year ended December 31, 2008 was 9.7 MMcfe/d, or approximately 19% of our 2008 total net equivalent production. The average net production from our South Texas properties for the nine months ended September 30, 2009 was 12.0 MMcfe/d, or approximately 28% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per operated net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.1 MMcfe/d and 0.2 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our South Texas properties were 60,602 MMcfe, of which approximately 94.6% were natural gas and natural gas liquids and 59.8% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 277.0 MMcfe. Our estimated net proved reserves at December 31, 2008 had an estimated PV-10 of $101.8 million.

Our average reserve life for this region is approximately 14 years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, seven gross (4.7 net) wells were drilled on our South Texas properties, 100% of which were successes. During the nine months ended September 30, 2009, one gross (0.4 net) well was drilled in South Texas (the Dubose #1), which has not been completed. In 2009, we currently expect to drill one gross well (0.3 net) on our South Texas resource play acreage. Also, as of September 30, 2009, we had identified 24 additional proved undeveloped drilling locations and over 100 other drilling locations on our South Texas leasehold acreage. Our drilling opportunities for South Texas have an average estimated well life of 15 years.

Southwest Louisiana

Our Southwest Louisiana properties consist primarily of the Fenton field area in Calcasieu Parish, acquired in the EXCO acquisition, and our legacy Grand Lake and Lacassine fields in Cameron Parish. In total, we own approximately 8,200 gross (3,600 net) acres in these large and prolific areas.

As of September 30, 2009, in Southwest Louisiana, we owned and operated 16 gross (10.0 net) producing wells. Our operated wells have an average net working interest of 51% and an average net revenue interest of 40%. We also owned 8,200 gross and 3,600 net acres in Southwest Louisiana.

The average net production from our Southwest Louisiana properties for the year ended December 31, 2008 was 5.9 MMcfe/d, or approximately 11% of our 2008 total net equivalent production. The average net production from our Southwest Louisiana properties for the nine months ended September 30, 2009 was 3.1 MMcfe/d, or approximately 7% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per operated net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.5 MMcfe/d and 0.4 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our Southwest Louisiana properties were 10,398 MMcfe, of which approximately 75.5% were natural gas and natural gas liquids and 57.3% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 397.5 MMcfe. Our estimated net proved reserves at December 31, 2008 had an estimated PV-10 of $27.2 million.

Colorado and Other

We also own properties in Colorado, Mississippi and other areas (Other Properties), none of which is a current area of focus for drilling. However, our Other Properties do serve to broaden our range and diversify our risk. These properties currently consist primarily of our legacy production and exploitation potential in the Denver Julesburg Basin in Colorado, which is primarily in Adams County. We own approximately 9,500 gross (6,700 net) undeveloped acres in this area that are held by production, that appear to be prospective in the basin and for which we will endeavor to find a local partner to participate in developing that acreage. We also own a minor crude oil property in Mississippi. Our Other Properties represent 6,675 MMcfe of proved reserves or 5.1% of our total proved reserves of December 31, 2008.

As of September 30, 2009, in our Colorado and Other Properties, we owned and operated 30 gross (22.0 net) producing wells. Our operated wells have an average working interest of 74% and an average net revenue interest of 59%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 17,500 feet. We principally produce from the Denver and Julesberg Sand formations in Colorado. We also own 16,900 gross (11,900 net) acres in these areas, most of which is held by production.

The average net production from our Colorado and Other Properties for the year ended December 31, 2008 was 0.9 MMcfe/d, or approximately 1.6% of our 2008 total net equivalent production. The average net production from our Colorado and Other Properties for the nine months ended September 30, 2009 was 0.5 MMcfe/d, or approximately 1% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.05 MMcfe/d and 0.01 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our Colorado and Other Properties were 6,675 MMcfe, of which approximately 71.5% were natural gas and natural gas liquids and 55.3% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 157.9 MMcfe. Our estimated net proved reserves at December 31, 2008 had an estimated PV-10 of $7.0 million.

Our average reserve life in this region is approximately 34 years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. We did not drill any wells on our Colorado and Other Properties in 2008 or during the first nine months of 2009. Our drilling opportunities for Colorado and Other Properties have an average estimated well life of 18 years. We recently contracted with a geological consulting group that specializes in the Denver Julesburg Basin, and that group has identified 151 drilling locations on our

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acreage as of September 30, 2009. Because of the upside potential, we are currently pursuing a relationship with an industry partner experienced in the Denver Julesburg Basin area to test that additional potential.

Non-Operated Properties

Though not a geographic region, we segregate our non-operated properties and treat them as a separate region, in order to allow our technical and operational teams dedicated to our operated regions to focus on those properties on which we have the ability to exercise operational and development control. Our non-operated properties consist primarily of our 25% working interest in the Samano field in Starr and Hidalgo Counties in South Texas, which we acquired in the Smith acquisition, our 28% working interest in certain fields in Liberty County in Southeast Texas and our 15% and 15% respective working interests resulting from exploratory successes in 2007 at Sabine Lake and West Cameron 432, in Southwest Louisiana.

As of September 30, 2009, we owned various working interests in 170 existing non-operated producing wells, with an average working interest of 25% and an average net revenue interest of approximately 19%. These wells produce crude oil and natural gas from various formations at depths from 2,000 to 17,500 feet.

The average net production from our non-operated properties for the year ended December 31, 2008 was 15.5 MMcfe/d, or approximately 29% of our 2008 total net equivalent production. The average net production from our non-operated properties for the nine months ended September 30, 2009 was 10.9 MMcfe/d, or approximately 25% of our total net equivalent production for the nine months ended September 30, 2009. The average net production per non-operated net well for the year ended December 31, 2008 and for the nine months ended September 30, 2009 was 0.4 MMcfe/d and 0.3 MMcfe/d, respectively.

Our estimated net proved reserves at December 31, 2008 for our non-operated properties were 24,879 MMcfe, of which approximately 92.5% were natural gas and natural gas liquids and 79.8% were classified as proved developed. The average remaining proved developed producing reserves per net well at December 31, 2008 was 385.5 MMcfe. Our estimated net proved reserves at December 31, 2008 had estimated PV-10 of $65.3 million.

Our average reserve life in this region is approximately six years based on our proved reserves as of December 31, 2008 and production for the nine months ended September 30, 2009 on an annualized basis. During 2008, 16 gross (3.7 net) wells were drilled on our Non-Operated properties, 88% of which were successes, and during the nine months ended September 30, 2009 we did not participate in any wells. Also, as of September 30, 2009, we had identified 22 additional proved undeveloped drilling locations and 60 other drilling locations on our non-operated leasehold acreage. A typical well in our non-operated properties has a predictable production profile and a standard economic life of approximately 19 years.

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Proved Reserves

The following tables reflect our estimated proved reserves at December 31 for each of the preceding three years. All information provided herein relating to our proved reserves is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us.

	2006	2007	2008
Crude Oil (MBbl)			
Developed	2,249	2,266	1,616
Undeveloped	252	637	948
Total	2,501	2,903	2,564
Natural Gas (MMcf)			
Developed	27,145	67,997	66,712
Undeveloped	4,243	23,242	29,457
Total	31,388	91,239	96,169
Natural Gas Liquids (Bbls)			
Developed		2,684	2,423
Undeveloped		906	976
Total		3,590	3,399
Total (MMcfe)	46,394	130,197	131,947
Proved developed reserves percentage	88%	75%	69%
PV-10 (in millions)(1)	$ 102.4	$ 531.4	$ 291.0
Estimated reserve life (in years)	17.5	9.8	6.9

(1) PV-10 is a non-GAAP financial measure. A reconciliation of our standardized measure to PV-10 is provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations.

The following tables reflect our estimated proved reserves by category as of December 31, 2008. Approximately 69% of our total proved reserves was classified as proved developed at December 31, 2008.

	Crude Oil (MBbl)	Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10

						(In millions)
Proved developed producing	1,165	48,458	1,630	65,227	49.4%	$ 180.1
Proved developed non-producing	451	18,254	793	25,718	19.5%	55.7
Proved undeveloped	948	29,457	976	41,001	31.1%	55.2
Total	2,564	96,169	3,399	131,946	100%	$ 291.0

The prices utilized in the estimation of our 2007 and 2008 proved reserves and PV-10 were based on the West Texas Intermediate posted prices on December 31, 2007 and December 31, 2008 of $97.50 and $41.00 per barrel for crude oil, respectively, and the Henry Hub spot market price of $6.80 and $5.71 per MMBtu for natural gas, respectively. The prices utilized in our estimation of our 2006 proved reserves were based on the NYMEX posted price on December 31, 2006 of $61.06 per barrel for crude oil and the NYMEX spot market price of $6.03 per MMBtu for natural gas. All prices were adjusted by lease for quality, energy content, transportation fees and regional price differentials.

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Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and standardized measure of discounted future net cash flows of our proved reserves, which were prepared in accordance with the rules and regulations of the SEC and the Financial Accounting Standards Board. Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of crude oil, natural gas and natural gas liquids production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. We cannot assure you that the proved reserves will all be developed within the periods used in the calculations or those prices and costs will remain constant.

	2006	2007	2008
		(In thousands)	
Future cash inflows	$ 313,313	$ 1,125,375	$ 749,121
Future production and development costs:			
Production	108,694	258,029	214,969
Development	26,229	65,779	86,068
Future cash flows before income taxes	178,390	801,567	448,084
Future income taxes	(43,534)	(198,921)	(46,696)
Future net cash flows after income taxes	134,856	602,646	401,388
10% annual discount for estimated timing of cash flows	(57,443)	(203,123)	(140,486)
Standardized measure of discounted future net cash flows	$ 77,413	$ 399,523	$ 260,902

All information provided herein relating to our proved reserves, estimated future net cash flows and present values is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC s guidelines, our estimates of proved reserves and the future net revenues from which present values are derived are made using year end crude oil and natural gas sales prices held constant throughout the life of the properties (except to the extent a contract specifically provides otherwise). Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report are based upon estimates. Reservoir engineering is a subjective process, which involves estimating the sizes of underground accumulations of crude oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation of that data and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing crude oil and natural gas prices, operating costs and other factors. Such revisions may be material. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. We cannot assure you that the estimates contained in this report are accurate predictions of our crude oil and natural gas reserves or their values. Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in potentially substantial variations in the estimated reserves.

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Significant Properties

Summary information on our properties with proved reserves is provided below as of December 31, 2008.

Regions	Productive Wells: Gross Productive Wells	Productive Wells: Net Productive Wells	Proved Reserves: Crude Oil (MBbl)	Proved Reserves: Natural Gas (MMcf)	Proved Reserves: Natural Gas Liquids (MBbl)	Total (MMcfe)	PV-10[(1)(2)] ($M)
South Texas	105	82	545	47,284	1,675	60,602	$ 101,838
Southeast Texas	35	27	965	17,669	988	29,393	89,685
Southwest Louisiana	21	12	425	6,490	227	10,398	27,162
Colorado and Other	25	19	317	4,775		6,675	7,002
Non-Operated	172	43	312	19,951	509	24,879	65,263
Total	358	183	2,564	96,169	3,399	131,947	$ 290,950

(1) The prices utilized in the estimation of our 2008 proved reserves were based on the West Texas Intermediate posted prices on December 31, 2008 of $41.00 per barrel for crude oil and the Henry Hub spot market price of $5.71 per MMBtu for natural gas. All prices were adjusted by lease for quality, energy content, transportation fees and regional price differentials.

(2) PV-10 is a non-GAAP financial measure. A reconciliation of our standardized measure to PV-10 is provided under Prospectus Summary Non-GAAP Financial Measures and Reconciliations.

Production, Revenue and Price History

The following table sets forth information (associated with our proved reserves) regarding production volumes of crude oil, natural gas and natural gas liquids, revenues and expenses attributable to such production (all net to our interests) and certain price and cost information as of December 31 for each of the preceding three years and for the nine months ended September 30, 2009:

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
Production				
Natural gas (Mcf)	1,542,423	9,067,777	13,135,509	8,142,588
Crude oil (Bbl)	184,881	408,864	498,143	264,170
Natural gas liquids (Bbl)		285,907	516,352	334,303
Total (Mcfe)	2,651,709	13,236,403	19,222,479	11,733,426
Revenue (in thousands)				
Natural gas sales	$ 10,570	$ 67,868	$ 116,415	$ 55,135
Crude oil sales	10,908	27,021	41,860	21,519

Natural gas liquids sales		14,273	27,405	9,089
Total	$ 21,478	$ 109,162	$ 185,680	$ 85,743

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
Production Data				
Average sales price (before hedging)				
Per Mcf of natural gas	$ 6.76	$ 6.78	$ 8.92	$ 3.92
Per barrel of crude oil	$ 63.29	$ 74.38	$ 101.13	$ 52.80
Per barrel of natural gas liquids		$ 49.92	$ 53.07	$ 27.19
Per Mcfe	$ 8.34	$ 8.02	$ 10.14	$ 4.68
Average sales price (after hedging)(1)				
Per Mcf of natural gas	$ 6.85	$ 7.48	$ 8.86	$ 6.77
Per barrel of crude oil	$ 59.00	$ 66.09	$ 84.03	$ 81.46
Per barrel of natural gas liquids	$	$ 49.92	$ 53.07	$ 27.19
Per Mcfe	$ 8.10	$ 8.25	$ 9.66	$ 7.31
Average expenses per Mcfe				
Lease operating	$ 2.12	$ 0.91	$ 1.08	$ 1.15
Production and ad valorem taxes	$ 0.71	$ 0.88	$ 0.85	$ 0.52
Exploration expenses(2)	$ 0.25	$ 0.24	$ 0.52	$ 0.52
Depreciation, depletion and amortization	$ 1.52	$ 2.23	$ 2.63	$ 3.55
General and administrative(3)	$ 3.29	$ 1.10	$ 1.17	$ 1.14

(1) Average sales prices are shown net of the settled amounts of our natural gas, crude oil and natural gas liquids hedge contracts.

(2) In November 2008, we released undeveloped leasehold interests that we acquired from Core Natural Resources in Culberson County, Texas in 2006, and recorded a $7.1 million exploration expense.

(3) Non-cash stock compensation expense on January 1, 2006 was $0.16, $0.26, $0.32 and $1.39 per Mcfe in the nine months ended September 30, 2009, the years ended December 31, 2008, 2007 and 2006, respectively.

Productive Wells

The following table shows the number of producing wells we owned by location at September 30, 2009:

	Gross Crude Oil Wells	Net Crude Oil Wells	Gross Natural Gas Wells	Net Natural Gas Wells
South Texas	1	1	93	72
Southeast Texas	7	6	28	21
Southwest Louisiana	8	6	8	4
Colorado and Other	21	15	9	7
Non-operated	18	3	152	40

Total	55	31	290	144

In addition, as of September 30, 2009, we had 171 inactive wells and 25 salt water disposal wells.

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Developed and Undeveloped Acreage

Developed acreage is acreage spaced or assigned to productive wells. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of natural gas, crude oil and natural gas liquids. Gross acres are the total acres in which we own a working interest. Net acres are the sum of the fractional working interests we own in gross acres. The following table shows the approximate developed and undeveloped acreage that we have an interest in, by location, at September 30, 2009.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
South Texas	74,100	39,500	16,300	14,000
Southeast Texas	23,400	12,800	3,900	2,300
Southwest Louisiana	7,200	2,700	1,000	900
Colorado & Other	7,400	5,200	9,500	6,700
East Texas	500	200	16,500	11,800
Total	112,600	60,400	47,200	35,700

Drilling Results

The following table shows the results of the wells drilled and completed for operated and non-operated properties for each of the last three fiscal years ended December 31, 2008 and the nine months ended September 30, 2009. No crude oil wells were drilled during this time period.

	December 31,			September 30,
	2006	2007	2008	2009
Gross Wells				
Development	4	9	20	4
Exploratory		8	5	
Dry		4	2	1
Total	4	21	27	5
Net Wells				
Development	3.50	1.07	10.74	1.74
Exploratory		1.65	1.05	
Dry		0.72	0.80	0.39
Total	3.50	3.44	12.59	2.13

At December 31, 2008, we had no exploratory and 4 gross (1.1 net) development wells in progress. At September 30, 2009, we had two gross (0.9 net) exploratory wells and no development wells.

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Costs Incurred

The following table shows the costs incurred in our crude oil and gas producing activities for the past three years and for the nine months ended September 30, 2009:

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
	(In thousands)			
Property Acquisitions:				
Proved	$	$ 238,036	$ 60,765	$ (494)
Unproved	8,745	30,408	57,203	1,490
Development Costs	6,466	30,815	86,685	10,859
Exploration Costs	10,784	13,405	2,520	7,248
Total	$ 25,995	$ 312,664	$ 207,173	$ 19,103

These costs include crude oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses and geological and geophysical expenses.

Property Dispositions

The following table shows crude oil and gas property dispositions for the three years ended December 31, 2008 and for the nine months ended September 30, 2009:

	December 31, 2006	December 31, 2007	December 31, 2008	September 30, 2009
	(In thousands)			
Crude oil and gas properties	$	$	$ 21,766	$ 11
Accumulated DD&A			(1,660)	
Crude oil and gas properties, net	$	$	$ 20,106	$ 11

The dispositions in 2008 resulted in a net gain of $15.2 million.

Marketing

We sell a significant portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to two years and crude oil production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for crude oil are tied to industry standard posted prices subject to negotiated price adjustments.

Competition

The oil and gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market crude oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining purchasers and transporters of the crude oil and natural gas we produce. There is also competition between producers of crude oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing gas and crude oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Title to Properties

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our crude oil and natural gas properties to secure our revolving credit facility and second lien term loan agreement. These mortgages and the credit facilities contain substantial restrictions and operating covenants that are customarily found in loan agreements of this type. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital resources and Covenant compliance.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the SEC. Recently enacted and proposed changes in the laws and regulations affecting public companies, including the provisions of the Sarbanes-Oxley Act of 2002 and rules adopted by the SEC, have resulted in increased costs to us. The new rules could make it more difficult for us to obtain certain types of insurance, including director and officer liability insurance, and we may be forced to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. The impact of these events could also make it more difficult for us to attract and retain qualified persons to serve on our board of directors, our board committees or as executive officers.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the release of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; or require remedial measures to mitigate pollution from current or former operations. Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed or reinterpreted, and any such changes or interpretations could have an adverse effect on our business.

Industry Regulations

The availability of a ready market for natural gas, crude oil and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of natural gas, crude oil and natural gas liquids production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of natural gas, crude oil and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be shut-in because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas, crude oil and natural gas liquids, protect rights to produce natural gas, crude oil and natural gas liquids between owners in a common reservoir, control the amount of natural gas, crude oil and natural gas liquids produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The following discussion summarizes the regulation of the United States oil and gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas, Crude Oil and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of crude oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of natural gas, crude oil and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act, or NGA, of 1938, the Federal Energy Regulatory Commission, or the FERC, regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act, or the Decontrol Act, deregulated natural gas prices for all first sales of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC s jurisdiction over natural gas transportation.

Under the provisions of the Energy Policy Act of 2005, or the 2005 Act, the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission, or CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. To the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC s regulations or an interstate pipeline s tariff could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978, or the NGPA, the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required pipelines, among other things, to perform open access transportation of gas for others, unbundle their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC s other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or lighter handed regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the Federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission, or the FTC, prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC s regulation of crude oil transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

Environmental Regulations

Various federal, state and local authorities regulate our operations with regard to air and water quality, release of substances and other environmental matters. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from current or former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. In addition, various laws and regulations require that well, pipeline, and facility sites be abandoned and reclaimed. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

We generate wastes that may be subject to the federal Resource Conservation and Recovery Act, as amended, or the RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or the EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have used good operating and waste disposal practices, prior owners and operators of these properties may not have used similar practices, and hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under our control. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, as amended, or the CERCLA, RCRA and analogous state laws as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, which impose strict, joint and several liability, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or

property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

Our operations may be subject to the Clean Air Act, as amended, or the CAA, and comparable state and local requirements. Amendments to the CAA adopted in 1990 contain provisions that have resulted in the gradual imposition of pollution control requirements with respect to air emissions from our operations. The EPA and states developed and continue to develop regulations to implement these requirements. We may be required to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. However, we do not believe our operations will be materially adversely affected by any such requirements.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill, which would establish an economy-wide cap-and-trade program to reduce greenhouse gas emissions, including carbon dioxide and methane by 17 percent from 2005 levels by the year 2020 and 80 percent by the year 2050. The U.S. Senate is considering a number of comparable measures. One such measure, the Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, has been reported out of the Senate Committee on Energy and Natural Resources, but has not yet been considered by the full Senate and also includes a cap-and-trade system for controlling greenhouse gas emissions in the United States. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of these bills remains uncertain, and such bills would have to undergo reconciliation before being adopted as law. Any laws or regulations that may be adopted to restrict or reduce emissions of U.S. greenhouse gases could require us to incur increased operating costs, and could have an adverse affect on demand for the oil and natural gas we produce. In addition, at least 20 states have already taken legal measures to control emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. In California, for example, the California Global Warming Solutions Act of 2006 requires the California Air Resources Board to adopt regulations by 2012 that will achieve an overall reduction in greenhouse gas emissions from all sources in California of 25% by 2020.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of crude oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of natural gas, crude oil and natural gas liquids, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the crude oil and natural gas we produce.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate carbon dioxide, or CO_2, emissions from automobiles as air pollutants under the CAA. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the CAA to regulate air pollutants from those and other facilities. On April 17, 2009, the EPA released a Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act. The EPA s proposed finding concludes that the atmospheric concentrations of several key greenhouse gases threaten the health and welfare of future generations and that the combined emissions of these gases by motor vehicles contribute to the atmospheric concentrations of these key greenhouse gases and hence to the threat of climate change. On September 15, 2009, EPA proposed a rule in anticipation of finalizing its findings to reduce emissions of greenhouse gases from motor vehicles, which rule is expected to be adopted in March 2010. Additionally, while the EPA s proposed findings do not specifically address stationary sources, those findings, if finalized, would be expected to support the establishment of future emission requirements

by the EPA for stationary sources. On September 23, 2009, the EPA finalized a greenhouse gas reporting rule establishing a national greenhouse gas emissions collection and reporting program. The EPA rules will require covered entities to measure greenhouse gas emissions commencing in 2010 and submit reports commencing in 2011. On September 30, 2009, EPA proposed new thresholds for greenhouse gas emissions that define when Clean Air Act permits under the New Source Review, or NSR, and Title V operating permits programs would be required. Under the Title V operating permits program, EPA is proposing a major source emissions applicability threshold of 25,000 tons per year (tpy) of carbon dioxide CO_2e (carbon dioxide equivalency) for existing industrial facilities. Facilities with greenhouse gas emissions below this threshold would not be required to obtain an operating permit. Under the Prevention of Significant Deterioration, or PSD, portion of NSR, EPA is proposing a major stationary source threshold of 25,000 tpy CO_2e. This threshold level would be used to determine if a new facility or a major modification at an existing facility would trigger PSD permitting requirements. EPA is also proposing a significance level between 10,000 and 25,000 tpy CO_2e. Existing major sources making modifications that result in an increase of emissions above the significance level would be required to obtain a PSD permit. EPA is requesting comment on a range of values in this proposal, with the intent of selecting a single value for the greenhouse gas significance level. These proposals, along with new federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the crude oil and natural gas we produce.

The U.S. Senate and House of Representatives are currently considering bills entitled, the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the federal Safe Drinking Water Act, or the SDWA, to repeal an exemption from regulation for hydraulic fracturing. If enacted, the FRAC Act would amend the definition of underground injection in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Although the legislation is still being developed, we do not expect the FRAC Act to have a material affect on our business because the Company contracts out all of its hydraulic fracturing work due to the specialized nature of the activity and the extensive capital investment required.

Federal regulations require certain owners or operators of facilities that store or otherwise handle crude oil to prepare and implement spill prevention, control, and countermeasure, or the SPCC, and response plans relating to the possible discharge of crude oil into surface waters. SPCC plans at our producing properties were developed and implemented in 1999. In December 2008, EPA amended the SPCC rule. On November 5, 2009, EPA signed a notice amending certain requirements of the SPCC regulations to address concerns from the regulatory community raised since the release of the December 2008 amendments. The new SPCC rule is expected to be effective January 14, 2010. Although EPA has not yet issued a final notice containing the new rules, it is clear that there will be changes impacting oil production facilities. These changes should not have a material adverse effect on us. The Oil Pollution Act of 1990, as amended, or the OPA, contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Our operations are also subject to the federal Clean Water Act, as amended, or the CWA, and analogous state laws. In accordance with the CWA, the state of Louisiana has issued regulations prohibiting discharges of produced water in state coastal waters effective July 1, 1997. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and

criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground.

CERCLA, also known as the Superfund law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a hazardous substance into the environment. These potentially responsible persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA 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, and 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 also are subject to a variety of federal, state and local permitting and registration requirements relating to protection of the environment. Our management believes that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse effect on us.

Employees

At September 30, 2009, we had 73 full time employees, of whom 23 were field personnel and seven were geoscientists. We have been able to attract a talented team of industry professionals from other industry peers that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets, and also to increase our proved reserves and production through acquisitions. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. During the second quarter of 2009, holders of oil and gas leases in East Texas (Haynesville Shale) filed two causes of action against us alleging breach of contract for not paying lease bonuses on certain oil and gas leases taken by our leasing agent. The damages alleged are approximately $2.8 million and there are approximately $300,000 in written demands from other holders of leases in this area that we believe may contemplate legal proceedings. We are vigorously defending these lawsuits, which we believe are completely without merit. We believe that the plaintiffs probability of success is remote and do not believe that these claims will have a material adverse affect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

Offices

We currently sublease, through January 31, 2014, 54,939 square feet of executive and corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Rent, including parking, related to this office space for the nine months ended September 30, 2009 was approximately $1.3 million.

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MANAGEMENT

Executive Officers and Directors

Our executive officers and directors as of the date of this prospectus are as follows. Each is a citizen of the U.S. unless otherwise indicated.

Name	Age	Position
Allan D. Keel	49	President, Chief Executive Officer and Director
E. Joseph Grady	56	Senior Vice President and Chief Financial Officer
Tracy Price	51	Senior Vice President Land/Business Development
Thomas H. Atkins	51	Senior Vice President Exploration
Jay S. Mengle	55	Senior Vice President Engineering
B. James Ford	41	Director
Adam C. Pierce	31	Director
Lee B. Backsen	69	Director
Lon McCain	61	Director

Allan D. Keel was appointed Chief Executive Officer and President and joined the Company s Board of Directors, or Board, on February 28, 2005. Before joining Crimson, Mr. Keel was Vice President/General Manager of Westport Resources, Houston office, during 2004. In this role he was responsible for its Gulf of Mexico operations including acquisitions, development and exploration. In 2003, Mr. Keel served as a consultant to both domestic and international companies in building their presence in the Gulf of Mexico. From mid-2000 until mid-2001, Mr. Keel served as a Vice President at Enron Energy Finance where he worked on private equity transactions and volumetric production payments. From mid-2001 through 2002, Mr. Keel served as President and CEO of Mariner Energy Company (Mariner), a majority owned affiliate of Enron. Subsequent to Enron s bankruptcy and its decision to sell Mariner, Mr. Keel partnered with Oaktree Capital Management in an effort to acquire Mariner. From 1996 until mid-2000, Mr. Keel was Vice President/General Manager for Westport Resources, where he built the Gulf of Mexico division from the grassroots. From 1984 to 1996, Mr. Keel was with Energen Resources where he directed the company s exploration, joint venture and acquisition activities. Mr. Keel was appointed pursuant to the terms of the Series G Preferred Stock. He received a Bachelor of Science degree and a Master of Science degree in Geology from the University of Alabama and a Masters of Business Administration degree from the Owen School of Management at Vanderbilt University.

E. Joseph Grady was appointed Senior Vice President and Chief Financial Officer on February 28, 2005. Mr. Grady is managing director of Vision Fund Advisors, Inc., a financial advisory firm he co-founded in 2001, and serves as an advisor to the board for the firm s privately-held investment and advisory clients. Mr. Grady has over 30 years of financial, operational and administrative experience, including over 20 years in the oil and gas industry. He was formerly Senior Vice President Finance and Chief Financial Officer of Texas Petrochemicals Holdings, Inc. from April 2003 to July 2004, Vice President-Chief Financial Officer and Treasurer of Forcenergy Inc. from 1995 to 2001 and held various financial management positions with Pelto Oil Company from 1980 to 1990, including Vice President-Finance from 1988 to 1990. Mr. Grady received a Bachelor of Science degree in Accounting from Louisiana State University.

Tracy Price was appointed Senior Vice President Land/Business Development on April 1, 2005. Mr. Price joined the Company after serving as the Senior Vice President- Land/Business Development for The Houston Exploration Company from 2001 until joining the Company. Prior to his tenure at The Houston Exploration Company, Mr. Price served as Manager of Land and Business Development for Newfield Exploration Company between 1990 and 2001. From 1986 to 1990 Mr. Price was Land Manager for Apache Corporation. Prior to Apache, Mr. Price served in similar land management capacities at Challenger Minerals Inc. and Phillips Petroleum Company. Mr. Price received a Bachelor of Business Administration degree in Petroleum Land Management from the University of Texas.

Thomas H. Atkins was appointed Senior Vice President Exploration on April 1, 2005. Mr. Atkins joined the Company after serving as the General Manager Gulf of Mexico for Newfield Exploration Company where he was employed from 1998 until joining the Company. Prior to his tenure at Newfield, Mr. Atkins served in various exploration capacities with EOG Resources and its predecessor companies from 1984 to 1998, including prospect generator, development geologist and finally as Exploration Manager. Mr. Atkins also worked at the Superior Oil Company from 1981 through 1984. Mr. Atkins received a Bachelor of Science degree in Geology from the University of Oklahoma.

Jay S. Mengle was appointed Senior Vice President Operations and Engineering on April 1, 2005, after serving as the Shelf Asset Manager Gulf of Mexico for Kerr-McGee Corporation subsequent to its 2004 merger with Westport Resources. Mr. Mengle was with Westport Resources from 1998 to 2004, where he started Westport s Gulf Coast/Gulf of Mexico drilling and production operations. Prior to joining Westport, Mr. Mengle also served in various drilling, production and marketing management capacities at Norcen Energy Resources, Kirby Exploration and Mobil Oil Corp. Mr. Mengle received his Bachelor of Science degree in Petroleum Engineering from the University of Texas.

B. James Ford became a member of the Company s Board on February 28, 2005. Mr. Ford is a Co-Portfolio Manager and Managing Director of Oaktree Capital Management, an affiliate of Oaktree Holdings. Before joining Oaktree Capital Management in June 1996, Mr. Ford was a consultant with McKinsey & Co., and a financial analyst in the Investment Banking Department of PaineWebber Incorporated. He currently serves as a director of EXCO, Cequel Holdings, Fu Sheng Industrial Co., Ltd., GAP Broadcasting Group, LLC and Verge Media Companies, Inc. Mr. Ford also serves as an active member of the Children s Bureau Board of Directors and as trustee of the Stanford Graduate School of Business Trust. Mr. Ford was appointed pursuant to the terms of the Series G Preferred Stock, the majority of which is held by Oaktree Holdings. Mr. Ford earned a Bachelor of Arts degree in Economics from the University of California at Los Angeles and a Masters of Business Administration degree from the Stanford University Graduate School of Business.

Adam C. Pierce was appointed to the Company s Board on January 24, 2008. Mr. Pierce is a Vice President of Oaktree Capital Management, an affiliate of Oaktree Holdings. Prior to joining Oaktree Capital Management in 2003, he was an investment banker with J.P. Morgan Chase & Company. Prior to joining J.P. Morgan Chase & Co., Mr. Pierce worked for Goldman Sachs. Mr. Pierce serves on the board of directors for several privately-held companies in which Oaktree Capital Management has invested. Mr. Pierce was appointed pursuant to the terms of the Series G Preferred Stock, the majority of which is held by Oaktree Holdings. Mr. Pierce received a Bachelor of Arts degree in Economics with a focus on Business Administration from Vanderbilt University.

Lee B. Backsen became a member of the Company s Board on June 1, 2005. Mr. Backsen is an oil and gas exploration consultant with over 45 years experience in the industry holding senior exploration management positions with Burlington Resources Inc., UMC Petroleum Corporation, General Atlantic Gulf Coast Inc., Kerr-McGee Corporation, Pelto Oil Company, Spectrum Oil and Gas Company and Shell Oil Company. From 2004 to 2008, Mr. Backsen was Vice President Exploration for Andex Resources, LLC, a private oil and gas producing company, and was responsible for sourcing exploration joint ventures. From 2000 to 2004, Mr. Backsen was a consulting geologist for Continental Land & Fur Co., Inc. and Grant Geophysical, Inc., for whom he screened exploratory prospects in the Texas and Louisiana Gulf Coast Basins. Mr. Backsen earned a Bachelor of Science degree and Masters of Science degree in Geology from Iowa State University.

Lon McCain became a member of the Company s Board on June 1, 2005. Mr. McCain was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a large, publicly traded exploration and production company, from 2001 until the sale of that company to Kerr-McGee

Corporation in 2004. From 1992 until joining Westport, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He currently serves as a director of Transzap Inc., Cheniere Energy Partners L.P. and Continental Resources Inc. Mr. McCain was an Adjunct Professor of Finance at the Daniels College of Business of the University of Denver from 1982 to 2004. Mr. McCain received a Bachelor of Science degree in Business Administration and a Masters of Business Administration/Finance from the University of Denver.

There are no family relationships between any of the executive officers or directors of Crimson Exploration.

Compensation of Directors

Name	Year	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	All Other Compensation ($)	Total ($)
B. James Ford(2)	2008	45,667			45,667
Lon McCain	2008	62,250	9,435		71,685
Lee B. Backsen	2008	49,667	9,435		59,102
Adam C. Pierce(2)	2008	47,667			47,667

(1) Includes the dollar amount of compensation expense we recognized for the fiscal year ended December 31, 2008. The awards for which compensation expense was recognized consist of awards granted on May 10, 2007 and July 22, 2008. The amounts above do not include awards granted on March 25, 2009 under the Plan for the 2008 service year. As of December 31, 2008, there were 10,160 shares outstanding granted pursuant to restricted stock awards to our directors.

(2) Messrs. Ford, Pierce and Baker, as employees of Oaktree Capital Management, elected not to receive stock awards during 2008, 2007 and 2006.

Upon the recommendation of the Compensation Committee, the Board approved on November 21, 2008, an amended compensation plan for non-employee directors (the Plan) providing for a $30,000 annual retainer, with a $2,000 meeting attendance fee ($1,000 if by telephone) for each full board, Audit and Compensation Committee meeting. The chairman of the Audit and Compensation Committee is entitled to receive an annual retainer of $13,500 and $6,000, respectively. The amended board compensation plan was effective June 1, 2008, which was the beginning of the 2008-2009 board year.

Under the Plan, each non-employee director receives $50,000 of restricted common stock for his first year of service subject to a three-year vesting schedule. Upon re-election, each non-employee director receives $50,000 in restricted common stock, subject to a one-year vesting requirement. The number of shares to be awarded is determined based on the fair market value of our common stock as of the close of trading on the date of grant.

The Plan replaced the previous director compensation plan for non-employee directors, which had been approved on June 1, 2005 and was in effect until May 31, 2008. Under the previous plan, non-employee directors were entitled to a $10,000 annual retainer, with a $2,000 meeting attendance fee ($1,000 if by telephone) for a maximum of $8,000 per director per year, with an additional fee payable for attendance of committee meetings held on days other than those on which the Board meets. The chairman of each of the Audit Committee and the Compensation Committee was also entitled to receive an annual retainer of $5,000 and $2,500, respectively.

In addition, the Plan provides for reimbursement of expenses for all directors in the performance of their duties, including reasonable travel expenses incurred attending meetings. Employee directors are not paid additional compensation for serving as a director.

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Board Composition

Under our certificate of incorporation and bylaws, the number of directors at any one time are set by resolution of the Board. Currently, the Board consists of five members, four of whom we expect will qualify as independent under the rules and regulations of the SEC and NASDAQ.

Our certificate of incorporation and bylaws provides for the annual election of directors. At each annual meeting of stockholders, our directors will be elected for a one-year term and serve until their respective successors have been elected and qualified. It is anticipated that the Board of Directors will meet at least quarterly.

The Board held six meetings during 2008. No director during the last fiscal year attended fewer than 75% of the total number of meetings of the Board and committees on which that director served.

Stockholders desiring to communicate with the Board may do so by mail addressed as follows: Board of Directors, Crimson Exploration Inc., 717 Texas Avenue, Suite 2900, Houston, Texas 77002. We believe our responsiveness to stockholder communications to the Board has been excellent.

The Company encourages, but does not require, directors to attend annual meetings of stockholders. At the Company s 2008 stockholder meeting, all members of the Board at the time of the meeting attended.

Board Committees

The Board has the authority to appoint committees to perform certain management and administrative functions. The Board has established a Compensation Committee and an Audit Committee and, prior to consummation of this offering, will establish a Corporate Governance and Nominating Committee. Following completion of this offering, the Audit Committee will have three members and each of the Compensation Committee and Corporate Governance and Nominating Committee will have two members, all of whom will qualify as independent under the rules and regulations of the SEC and NASDAQ.

Audit Committee

The Audit Committee was established to review and appraise the audit efforts of our independent accountants, and monitor our accounts, procedures and internal controls. During 2008, the Audit Committee consisted of Mr. McCain and Mr. Pierce. Mr. Pierce replaced Mr. Skardon F. Baker, who served on the Audit Committee until his resignation from the Board on January 24, 2008. The Audit Committee met four times in 2008. The Board has determined that Mr. McCain is an audit committee financial expert as defined under applicable rules and regulations of the SEC. Our Audit Committee has adopted a charter, which is posted on our website www.crimsonexploration.com under Corporate Governance.

Compensation Committee

The function of the Compensation Committee is to recommend for approval by the Board the annual salaries and other compensation for our executive officers and key employees. Our Compensation Committee consists of Messrs. Ford and Backsen. The committee met three times in 2008. Our Compensation Committee has adopted a written charter, which is posted on our website www.crimsonexploration.com under Corporate Governance. The Compensation Committee has the following authority and responsibilities:

To establish and review our overall compensation philosophy;

To review and approve corporate goals and objectives relevant to our executive officers compensation, evaluate the performance of such officers and recommend for approval by the Board, the benefits, direct and indirect, of our executive officers based on this evaluation;

To review and recommend to the Board for approval all our equity compensation plans that are not otherwise subject to the approval of the stockholders;

To review and make recommendations to the Board for approval of all equity awards;

To review and monitor all employee pension, profit-sharing and benefit plans, if any; and

To make recommendations to the Board with regard to our compensation and benefit programs and practices for all employees.

While the Compensation Committee is not prohibited from delegating its functions, the Compensation Committee has not done so in the past, although it may consider senior management s recommendations regarding appropriate compensation for members of management reporting to them, as discussed under Compensation Discussion and Analysis below.

Corporate Governance and Nominating Committee

Prior to this offering the Board did not have a Corporate Governance and Nominating Committee and the functions of this committee were performed by the whole Board. In connection with this offering, the Board of Directors will appoint two directors to serve as the members of the Corporate Governance and Nominating Committee. The Corporate Governance and Nominating Committee will identify and recommend nominees to the Board of Directors and oversee compliance with our corporate governance guidelines. Prior to the completion of this offering the Corporate Governance and Nominating Committee will adopt a written charter addressing director nominations and post a copy on our website www.crimsonexploration.com under Corporate Governance.

The Board believes that candidates for director should have certain minimum qualifications, including being able to read and understand financial statements and having the highest personal integrity and ethics. Previously the Board has, and after this offering the Corporate Governance and Nominating Committee will, consider such factors as relevant expertise and experience, ability to devote sufficient time to the affairs of the Company, demonstrated excellence in his or her field, the ability to exercise sound business judgment and the commitment to rigorously represent the long-term interests of the Company s stockholders. Candidates for director will be reviewed in the context of the current composition of the Board, the operating requirements of the Company and the long-term interests of stockholders.

The Board currently does not, and immediately following this offering the Corporate Governance and Nominating Committee will not, have a formal process in place for identifying and evaluating nominees for directors. Instead, the Corporate Governance and Nominating Committee will use its network of contacts to identify potential candidates. The Corporate Governance and Nominating Committee will conduct any appropriate and necessary inquiries into the backgrounds and qualifications of possible candidates after considering the function and needs of the Board. The Corporate Governance and Nominating Committee will meet to discuss and consider such candidates qualifications and then select a nominee for recommendation to the Board by a unanimous vote.

The Board has not established procedures for considering nominees recommended by stockholders. The Board believes that nominees should be considered on a case-by-case basis on each nominee s merits, regardless of who recommended such nominee.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serves, or has served during the past fiscal year, as a member of the board of directors or compensation committee of any other company that has one or more executives serving as a member of our board of directors or compensation committee.

Code of Ethics

We have adopted a code of ethics as defined by the applicable rules of the SEC, and it has been posted on our website at www.crimsonexploration.com.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

The following Compensation Discussion and Analysis contains statements regarding future individual and company performance targets and goals. These targets and goals are disclosed in the limited context of our executive compensation program and should not be understood to be statements of management s expectations or estimates of results or other guidance. We specifically caution stockholders not to apply these statements to other contexts.

Introduction

This Compensation Discussion and Analysis (1) provides an overview of our compensation policies and programs; (2) explains our compensation objectives, policies and practices with respect to our executive officers; and (3) identifies the elements of compensation for each of the individuals identified in the following table, whom we refer to in this Compensation Discussion and Analysis as our named executive officers.

Name	Principal Position
Allan D. Keel	Chief Executive Officer and President
E. Joseph Grady	Senior Vice President and Chief Financial Officer
Tracy Price	Senior Vice President Land/Business Development
Jay S. Mengle	Senior Vice President Operations and Engineering
Thomas H. Atkins	Senior Vice President Exploration

Objectives and Philosophy of Our Executive Compensation Program

Due to an aging of the industry employee base, and a shortage of new entrants into the industry, competition for high-caliber personnel experienced in the oil and gas industry has become very intense. Accordingly, the objective of our compensation program is to establish a competitive compensation program with appropriate compensation packages for the wide variety of duties performed by our named executive officers. In addition, we have sought to establish a competitive compensation program that motivates our executive officers to enhance long-term stockholder value.

Recognizing that attracting, retaining and motivating our executive officers to successfully perform demanding roles is critical to meeting our strategic business and financial goals, our compensation philosophy is that the compensation paid to our executive officers should be directly and materially linked to our achievement of our specific annual, long-term and strategic goals and to each officer s individual contribution to the attainment of those goals. We believe our overall compensation strategy of offering a balanced combination of annual and long-term compensation to our executive officers based upon corporate and individual performance helps maximize stockholder return.

To achieve these objectives, we have historically evaluated the compensation paid to our executive officers based upon the following factors:

- the appropriate mix of salary, cash incentives and equity incentives;
- company growth and financial and operational performance, as well as individual performance; and

market analysis of the compensation packages of our executive officers compared to the compensation packages of executive officers at other oil and gas industry companies that are similar to ours in their operations, among other factors.

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Except as otherwise noted below, we do not assign relative weights or rankings to these factors. Instead, the Compensation Committee makes subjective determinations of compensation levels based upon a consideration of all of these factors.

Setting Executive Compensation

On behalf of our Board, the Compensation Committee reviews, evaluates and approves all compensation for our executive officers, including our compensation philosophy, policies and plans. Our Chief Executive Officer and Chief Financial Officer also play important roles in the executive compensation process, including evaluating the other executive officers and assisting in the development of performance target goals. For example, at least once each year the Chief Executive Officer and Chief Financial Officer present to the Compensation Committee their evaluation of each of the other named executive officers (including, the Chief Executive Officer s evaluation of the Chief Financial Officer), which includes a review of contribution and performance over the past year, strengths, weaknesses, development plans and succession potential. Following these presentations and a review of all relevant data, the Compensation Committee makes its own assessments and recommends to the Board approval of the compensation for each named executive officer. Although the Chief Executive Officer and the Chief Financial Officer each may make recommendations to the Compensation Committee regarding his own compensation, to the extent events or circumstances are applicable to all named executive officers as a group regarding compensation decisions, all final decisions regarding executive compensation remain with the Compensation Committee or our Board. In this way all compensation elements are reviewed and approved by the Compensation Committee or our Board. The Compensation Committee does take into consideration the named executive officers total compensation, including base salary annual incentives and long-term incentives, both cash and equity, when considering market based adjustments to the named executive officers compensation.

In January 2008, the Compensation Committee retained Longnecker & Associates, an experienced compensation consulting firm that specializes in the energy industry and that has access to national compensation surveys and our compensation information, to conduct a company-wide review of our compensation policies and programs to determine our level of competitiveness in the oil and gas industry and advise the Compensation Committee as to whether modifications should be adopted in order to attract, motivate and retain key employees. The Compensation Committee is compensated by the Company. After our acquisition of the STGC Properties from EXCO in 2007, which significantly increased the size of our company, we felt that it had become increasingly important, given our growing need for highly skilled and experienced personnel in highly competitive labor market, to take additional measures to ensure that we were appropriately compensating our key employees and rewarding performance in a manner consistent with similar employers of a similar size. Additionally, the initial terms of the employment contracts for Messrs. Keel and Grady were set to expire in 2008, and the initial terms of the employment contracts for Messrs. Price, Mengle and Atkins expired in 2007. Accordingly, for these reasons we felt that it was appropriate to engage a compensation consultant at the beginning of 2008 to assist the Compensation Committee in its compensation review. The results of that review, as well as the latest ECI surveys using data from the selected Peer Group, were utilized by the Compensation Committee in determining and modifying the executive compensation levels for fiscal 2008. The Compensation Committee determined that no changes to executive compensation levels were necessary for fiscal 2009 upon the recommendation of the Chief Executive Officer and Chief Financial Officer.

The Compensation Committee did not retain independent compensation consultants to assist it in evaluating executive compensation matters for fiscal years 2006 or 2007. Instead, the Compensation Committee made comparisons of our executive compensation program to the compensation paid to executives of other companies within the oil and gas industry. Energy industry compensation surveys from Effective Compensation Inc. (ECI) were used. ECI surveys were utilized as they are specific to the energy industry and derive their data from direct contributions from a large number of participating companies that we consider to be our peers. The ECI surveys compile data from most companies that

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we currently consider to be in our peer group, as well as companies somewhat larger than us but with which we compete for talent. The surveys were used to compare our executive compensation program against companies (the Peer Group) that have comparable market capitalization, revenues, capital expenditure budgets, geographic focus and number of employees.

With respect to compensation decisions made in 2008, the selected Peer Group for 2008 included Swift Energy Company, Comstock Resources, Inc., Continental Resources, Inc., Energy XXI, PetroQuest Energy, Inc., Concho Resources, Inc., Callon Petroleum Company, Delta Petroleum Corp., Edge Petroleum Corp., Goodrich Petroleum Corporation, Dune Energy, Inc. and Gastar Exploration Limited. The Compensation Committee regularly reviews and refines the Peer Group as appropriate. When we refer to peers, peer group or peer companies or similar phrases, we are referring to this list of companies, as it may be updated by the Compensation Committee from time to time.

The Company believes that each element of compensation has been designed to complement the other components and, when considered together, to meet the Company s compensation objectives; however, the Company does not have a policy or target for the allocation between short-term and long-term or cash and non-cash incentive compensation.

Elements of Our Executive Compensation Program

General

The principal components of our executive compensation program include:

- base salary;
- performance-based cash incentive compensation;
- discretionary cash incentive compensation;
- long-term equity-based incentive compensation;
- overriding royalty interest plan compensation;
- severance benefits; and
- other health and fringe benefits.

Base Salary

We provide base salaries to our executive officers to compensate them for services rendered during the year at levels that we believe are competitive in the oil and gas industry and that are designed to allow us to attract, motivate and retain executive officers. Base salaries are a major component of the total annual cash compensation paid to our executive officers and are reviewed annually by the Compensation Committee. Base salary determinations are made by the Board taking into consideration salary recommendations from the Compensation Committee. The Compensation Committee will consider senior management s recommendations as to appropriate compensation for members of management reporting to them.

All of our executive officers are subject to employment agreements that provide for a fixed base salary. These salaries were determined after taking into account many factors, including:

the historic salary structure within our company;

the responsibilities of the officer;

the scope, level of expertise and experience required for the officer s position;

the strategic impact of the officer s position;

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the potential future contribution and demonstrated individual performance of the officer; and

salaries paid for comparable positions at similarly-situated companies.

At the time the employment agreements were entered into, we set base salaries at the base salary comparables at or near the 50th percentile of salaries of comparable executive officers of what we considered our peer group of companies. After a consideration of the factors described above, we did not increase the base salary levels of our named executive officers during fiscal 2006 or 2007. Subsequent changes to those initial salaries were made after consideration of our performance, individual performance and competitive salaries prevalent in the oil and gas industry. In early 2008, our Board, based on the recommendation of the Compensation Committee, approved increases to the annual base salaries of the named executive officers as follows:

Name	**Former Base Salary**	**New Base Salary**
Allan D. Keel	$ 240,000	$ 370,000
E. Joseph Grady	$ 220,000	$ 340,000
Jay S. Mengle	$ 180,000	$ 220,000
Thomas H. Atkins	$ 180,000	$ 200,000
Tracy Price	$ 185,000	$ 200,000

In addition, in 2008 our Board approved and we entered into amended and restated employment agreements with our named executive officers to reflect these base salary increases and to, among other things, modify provisions relating to the federal income tax treatment of certain arrangements in order to meet the December 31, 2008 deadline for compliance with Section 409A of the Internal Revenue Code of 1986, as amended (the Code), reflect other market-based changes in compensation approved in early 2008 by the Compensation Committee and provide for new terms of the agreements, since the initial terms of the existing employment agreements expired. This Code section governs the treatment of deferred compensation which is broadly defined and thus has the potential to impact numerous types of compensation arrangements between us and our employees. If violated, Section 409A can result in adverse tax consequences to the employee. The Section 409A amendments to our compensation arrangements were intended to prevent any such adverse tax result on our employees. See Narrative Disclosure to Summary Compensation Table and Grants of Plan Based Awards Table Employment Agreements.

Performance-Based Cash Incentive Compensation

All of our employees, including our named executive officers, are eligible to participate in an annual, performance-based cash incentive compensation plan that is designed to reward employees on the basis of our company attaining pre-determined performance measures.

The Compensation Committee annually approves the quantitative performance goals for five separate categories under the plan, usually within the first two months of the plan year. The categories are reviewed annually by the Compensation Committee with input from our executive officers and adjusted, as needed, in order to reflect our current structure and operations. For fiscal 2007 and 2008, the categories consisted of the following:

Oil and Gas Production Levels (Production). The Production goal is based on targeted performance levels for the fiscal year.

Earnings Before Interest, Taxes, Depreciation, Amortization and Exploration Expenses (EBITDAX). EBITDAX is a non-GAAP measure we use as an approximation of net income (loss). Our definition of EBITDAX may differ from that of other companies and excludes Exploration (Geological & Geophysical) expenses, Exploration Dry Hole Costs (DHC) and other non-cash charges normally considered expenses by oil and gas companies utilizing successful efforts method of accounting.

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Replacement of Oil and Natural Gas Reserves Depleted by Production (Reserve Replacement). Reserve Replacement is a measure of our ability to replace oil and gas reserves over and above equivalent reserves depleted by oil and gas production during the fiscal year.

Finding and Development Costs (F&DC). F&DC measures the cost to locate prospects, acquire production rights, drill and complete wells and install or construct production equipment and facilities per equivalent unit of proved reserves added ($/Mcfe) during the fiscal year, inclusive of revisions of prior year reserve estimates.

Return on Invested Capital (ROIC). ROIC is a measure of earnings before taxes (but excludes certain expenses, including exploration costs and dry hole costs, non-cash equity-based compensation expenses, gains/losses from mark to market accounting on derivatives and gains/losses from asset impairment), divided by average stockholders equity for the year (consisting of the par value of our preferred stock and common stock plus additional paid-in capital).

Each performance category was selected based on the Compensation Committee s belief that it most accurately measures our corporate performance in relation to comparable oil and gas companies within our peer group.

Each year, the Compensation Committee establishes the minimum, target and maximum performance levels for each of the five performance categories and their appropriate weighting. For each executive officer, the Compensation Committee determines the appropriate percentage allocation to be assigned for each category. In most cases, when determining an executive officer s bonus, the Compensation Committee gives equal weight to each category except when a particular performance category bears a more direct relationship to the executive officer s areas of responsibility, in which case a particular performance category may be more heavily weighted. The weighting for each named executive officer for fiscal 2007 for each of the five categories was as follows:

Category	**Mr. Keel**	**Mr. Grady**	**Mr. Price**	**Mr. Mengle**	**Mr. Atkins**
Production	20%	20%	20%	30%	10%
EBITDAX	20%	20%	20%	20%	10%
Reserve Replacement	20%	20%	20%	20%	35%
F&DC	20%	20%	20%	20%	35%
ROIC	20%	20%	20%	10%	10%

For fiscal 2008, the Compensation Committee determined weights to be assigned to each performance category, based on the importance of each category to our overall success, and applied to each executive officer equally. The weighting assigned to each performance category applicable to Messrs. Mengle and Atkins was modified for fiscal 2008 in order to better reflect the overall contribution of these officers to the performance goals of the Company for 2008. The weighting for each named executive officer for fiscal 2008 for each of the five categories is as follows:

Category	**Fiscal 2008**
Production	20%
EBITDAX	20%
Reserve Replacement	20%
F&DC	20%

ROIC	20%

Should our financial and operating results meet or exceed either the pre-determined minimum, target and maximum values assigned a particular performance category (with linear interpolations between each level), then each executive officer is paid an annual bonus that is a percentage of their annual salary. The Compensation Committee retains the right to make what it determines to be appropriate adjustments to actual results for the year, to the extent it believes that adjustments are warranted. For example, in determining the actual level of EBITDAX and ROIC for a particular year, it may exclude the effects of certain non-cash income/expense items such as the mark to market benefit/charge to our results of operations as required by GAAP and non-cash charges to our results of operations related to non-cash equity-based compensation charges for stock options or the variance in EBITDAX and ROIC caused by the variance in realized oil and gas prices compared to those incorporated into the performance goals (since prices are largely not within management s control).

For fiscal 2007, the Compensation Committee established the target bonus percentage for each executive officer after taking into account the importance of the position held by that officer to us achieving our performance goals during the year as well as published compensation surveys. The actual percentage of annual salary that was paid as an annual cash incentive bonus for 2007 ranged from 20% to 100% of the annual salaries for Messrs. Keel and Grady and from 20% to 70% of the annual salaries for Messrs. Price, Mengle and Atkins. The maximum values were originally determined at the time we entered into the employment agreements with each executive officer.

For fiscal 2008, as part of our compensation review process, the Compensation Committee in mid-2008 revised the target bonus percentage for each executive officer after taking into account Longnecker & Associates data and suggestions. As a result of this revision, the actual percentage of annual salary to be potentially paid as an annual cash incentive bonus for 2008 ranged from 50% to 120% of the annual salaries for Messrs. Keel and Grady and from 40% to 100% of the annual salaries for Messrs. Price, Mengle and Atkins. This adjustment was made so that our Performance-Based Cash Incentive Compensation Plan would be more in line with performance-based incentive plans offered to the executive officers of companies we consider to be in our peer group in our industry.

The actual percentage of annual salary potentially paid to an executive officer as a bonus is dependent upon the extent to which we meet or exceed our pre-determined performance goals. Payment of annual cash incentive bonuses to our executive officers is not guaranteed and is based upon our actual performance during the fiscal year, including meeting at least the minimum performance targets we set. Bonuses are typically paid out in cash during the first quarter of the year following the fiscal year in which they are earned, at the discretion of the Compensation Committee.

The Compensation Committee established the minimum, target and maximum performance levels (with linear interpolations between each level) for fiscal 2008 as follows:

The minimum level is equal to 80% of the target level of performance goal and is the level at which payout under the plan begins for the applicable performance measure. If the actual performance level for a measure is below the minimum level, no payout occurs with respect to that measure.

The target level is that at which 100% of the applicable performance goal is attained, and represents the expected payout level.

The maximum level is that at which 120% of the applicable target performance goal is attained.

After giving consideration to past Company performance and peer performance, the Compensation Committee set these performance levels so that the attainment of the targets is not assured and requires significant effort by our executives. We believe that the disclosure of performance targets would result in competitive harm to us and are therefore omitted since we are engaged in a highly competitive business, we may pursue opportunities in areas without first publicly disclosing our intention to do so and disclosure of these targets might enable our competitors to determine our strategic areas of interest and priorities throughout the year. We also believe that disclosure of our performance targets would undermine our on-going efforts to retain officers and other employees in a competitive employment atmosphere. Our business is highly dependent on attracting and keeping

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qualified, skilled employees. We believe that public disclosure of the performance targets used to determine the named executive incentive compensation would materially increase the ability of competitors to track current year bonus potential and tailor compensation packages designed to persuade officers and other employees to leave the Company. In addition, it would give our competitors an unfair informational advantage with respect to competing for prospective employees.

The Compensation Committee adjusted the minimum, target and maximum performance levels from 40%, 100% and 115% for 2007, respectively, to the current levels for 2008 because the prior performance levels were not reflective of competitive incentive compensation levels offered by the Company s industry peer group companies.

For fiscal 2008, as part of our compensation review process, our Board, upon the recommendation of our Compensation Committee revised the minimum, target and maximum performance levels (with linear interpolations between each level) as that at which 80%, 100% and 120% of the expected applicable target performance goal for each measure will occur, respectively.

In 2008, in recognition of the Company s low stock price, the Company s strategy of conserving cash to pay down debt during this low commodity price environment and the negative reserve revisions at the end of 2008, the Company s executives voluntarily waived the performance-based cash incentive compensation to which they were entitled under the plan for the 2008 fiscal year.

If the Company s executives had not voluntarily waived the performance-based cash incentive compensation to which they were entitled under the plan for the 2008 fiscal year, each executive s compensation would have been as follows:

Name	**2008 Base Salary**	**2008 Performance-Based Cash Incentive Compensation**
Allan D. Keel	$ 370,000	$ 117,237
E. Joseph Grady	$ 340,000	$ 107,732
Tracy Price	$ 200,000	$ 51,825
Jay S. Mengle	$ 220,000	$ 55,935
Tommy H. Atkins	$ 200,000	$ 51,730

As a result of anticipated low commodity prices for 2009 and the corresponding negative impact on revenues, a reduced capital expenditure budget, and the resulting impact on the ability to formulate meaningful performance goals for the plan for 2009, upon the recommendation of the Compensation Committee, the Board has suspended the performance-based cash incentive compensation plan for the executive officers and all other Company employees for the fiscal year ending December 31, 2009.

Discretionary Cash Incentive Compensation

As one way of accomplishing our executive compensation program objectives, the Compensation Committee has the ability to award discretionary cash bonuses to our executive officers for their contribution to our financial and operational success. These amounts are in addition to amounts awarded under our annual performance-based cash incentive compensation plan, and are typically awarded in cases where awards under our performance incentive plans are not commensurate with the performance and contribution of any individual executive.

In March 2008, Mr. Atkins was awarded a discretionary cash bonus of $40,000 in recognition of his success in developing an internal prospect generation capability, including a technical team, which was an individual effort that the Compensation Committee believed was not adequately rewarded under the annual cash incentive compensation plan described above. No other discretionary cash bonuses were awarded to any executive officer in, or for, year 2008 performance.

Long-Term Equity-Based Incentive Compensation

We grant equity awards to give our executive officers a longer-term stake in the Company, act as a long-term retention tool and align employee and stockholder interests by increasing compensation as stockholder value increases. In addition, the Compensation Committee occasionally grants equity awards in recognition of outstanding service to the Company. To achieve these objectives, the Compensation Committee has generally relied on the issuance of restricted stock and stock options.

General

We believe that stock options reduce stockholder dilution, conserve shares available under our stock plans, align employees compensation goals with the creation of stockholder value and encourage our executive officers to take necessary and appropriate steps to increase our stock price. We believe that restricted stock encourages our executive officers to adopt a view towards long-term value while providing a retention incentive even in the event of a decline in the stock price. The Board believes that stock options and restricted stock awards are an effective incentive for executive officers, managers and other key employees to create value for us and our stockholders since the value of restricted stock and options bear a direct relationship to appreciation in our stock price. In addition, by using stock-based compensation, we can focus much needed cash flow, which would otherwise be paid out as compensation, back into the daily operations of our business.

No stock options were granted to our executive officers in fiscal 2006, 2007 or 2008. We chose to provide equity compensation in the form of restricted stock rather than stock options because restricted stock awards incentivize our executive officers to build long-term value for our stockholders and provide a greater retention incentive in the current economic environment and at this stage of the Company s development.

For fiscal 2008, as part of our compensation review process, we made several changes to our long-term equity-based incentive compensation. We made these changes to improve the retention incentives for our executive officers and to provide better incentives for the creation of long-term value for our stockholders.

In September 2008, we provided our five named executive officers and six other employees holding outstanding stock options with an exercise price of $17.00 per share (which were initially granted to our executives in connection with the recapitalization of the Company in 2005 and to the other employees as part of their initial compensation package) the option to exchange their substantially vested stock options for shares of unvested restricted stock at the rate of two stock options for one share of restricted stock. The ratio of options to shares of restricted stock was based on an estimated valuation of the exchanged options, which were substantially vested but out-of-the money, as compared to an estimated value for a number of equivalent unvested shares of restricted common stock, taking into account market prices and the proposed vesting schedule, among other factors. All of our executive officers agreed to exchange their $17.00 options for shares of restricted stock. The restricted stock granted pursuant to the exchange offer will vest as follows:

- 50% of the restricted shares received by each holder will vest over four years at a rate of 25% each year, or 100% upon a change of control or 100% upon the death or disability of an executive officer; and

- 50% of the restricted shares received by each holder will vest upon the earlier of the fifth anniversary of the grant date or a change of control or upon the death or disability of an executive officer.

LTIP

In addition, our Compensation Committee and Board also approved in 2008 a performance-based long-term equity incentive plan (the LTIP) designed to reward employees with equity based compensation on the basis of the Company attaining pre-determined performance measures, similar to our performance-based cash incentive compensation plan. All grants made under the LTIP are performance based, are calculated as a percentage of base salary earned during the plan year and are to be made in the form of restricted stock and stock option grants under the 2005 Stock Incentive Plan. All restricted stock awards and stock options granted pursuant to this plan will vest over four years at a rate of 25% each year.

In 2008 we amended our 2005 Stock Incentive Plan to increase the maximum aggregate number of shares of common stock which may be issued upon exercise of all awards under the 2005 Stock Incentive Plan by one million shares, and among other things, to accommodate LTIP awards, to make certain adjustments for the Company s reincorporation from Texas to Delaware, to make other changes to conform the 2005 Stock Incentive Plan s provisions to the final regulations under Section 409A of the Code and for certain other conforming and clarifying changes.

The pre-determined performance measures will be the same as the measures under the performance-based cash incentive compensation plan and consistent with our existing criteria for performance awards under our 2005 Stock Incentive Plan: (i) Production; (ii) EBITDAX; (iii) Reserve Replacement; (iv) F&DC; and (v) ROIC.

The Compensation Committee has established the minimum, target and maximum performance levels for each of these five performance categories and their appropriate weighting. The weighting assigned to each performance category is based on the importance of each category to our overall success, and are to be applied to each executive officer equally. The weighting for fiscal 2008 for each of the five categories was as follows:

Category	**Fiscal 2008**
Production	20%
EBITDAX	20%
Reserve Replacement	20%
F&DC	20%
ROIC	20%

Should our financial and operating results meet or exceed either the pre-determined minimum, target and maximum values assigned a particular performance category with linear interpolations between each level, then each executive officer is granted a dollar value of restricted stock awards and stock options based on a percentage of his or her annual salary.

The Compensation Committee established the minimum, target and maximum performance levels for fiscal 2008 as follows:

The minimum level is equal to 80% of the target level and is the level at which payout under the plan begins for the applicable performance measure. If the actual performance level for a measure is below the minimum level, no payout occurs with respect to that measure.

The target level is that at which 100% of the expected payout for the applicable performance measure will occur.

The maximum level is that at which 150% of the expected payout for the applicable performance measure will occur.

After giving consideration to past company performance and peer performance, we have set these performance levels so that the attainment of the targets is not assured and requires significant effort by our executives.

The actual percentage of annual salary paid to an executive officer as a bonus is dependent upon the extent to which we meet or exceed our pre-determined performance goals. Payment of annual equity incentive bonuses to our executive officers is not guaranteed and will be based upon our actual performance during the fiscal year, including meeting at least the minimum performance targets. The Compensation Committee does not have the discretion to modify the minimum, target and maximum levels for a fiscal year.

All grants will consist of 50% restricted stock awards and 50% stock option awards. The restricted stock awards will be based on our stock price at the time of the grant, and the dollar value of the stock options will be calculated using the Black-Scholes option pricing model.

For fiscal 2008, the Compensation Committee established the target bonus percentage for each executive officer after taking into account the position held by that officer and the importance of that officer to achieving our performance goals during the year, as well as published compensation surveys. The actual percentage of annual salary to be paid as the annual equity incentive bonus in 2008 ranged from 75% to 450% of the annual salary of Mr. Keel, 75% to 350% of the annual salary of Mr. Grady and from 50% to 300% of the annual salaries for Messrs. Price, Mengle and Atkins.

Mr. Keel s annual equity incentive bonus potential is higher than that of other currently employed executives primarily because of the compensation levels of comparable executives of peer group companies against whom his compensation is targeted and his greater influence over and responsibility for the entire Company. In addition, Mr. Keel s compensation reflects his leadership in developing strategic alternatives for the Company to enhance stockholder value.

Mr. Grady s annual equity incentive bonus potential is higher than that of other named executive officers, except for that of Mr. Keel, primarily because of his seniority, experience and stature in the industry, his reporting relationship to the Chief Executive Officer, the compensation levels of comparable executives of peer group companies against whom his compensation is targeted and his greater influence over and responsibility for the entire Company.

Mr. Price s, Mr. Mengle s and Mr. Atkins annual equity incentive bonus potential levels reflect their roles and responsibilities as officers of the Company and their individual contributions to the Company and the officer team.

For fiscal 2008, equity grants under the plan were approved during the first quarter of 2009, at the recommendation of the Compensation Committee and approval of the Board. See Narrative Disclosure to Summary Compensation Tables and Grants of Plan-Based Awards Table Stock Awards. For fiscal 2009, equity grants under the plan were suspended at the recommendation of the Compensation Committee as a result of anticipated low commodity prices for 2009 and the corresponding negative impact on revenues and a reduced capital expenditure budget.

Overriding Royalty Interest Plan Compensation

We provide compensation to our executive officers through our Overriding Royalty Interest Plan (the ORRI Plan), which is designed to reward the efforts of employees who are successful in exploring for oil and natural gas on our behalf. The program is available only to those employees that are directly involved in oil and natural gas exploration efforts, including Mr. Atkins, our Senior Vice President Exploration, who is the only named executive officer entitled to benefits under this plan. In order to be able to participate in the plan, a potential candidate must be recommended for participation by our president and approved by the Compensation Committee. Under the ORRI Plan, the participants share a portion of the gross revenue interest attributable to the original working interest held by us in certain of the oil and natural gas producing properties generated by the exploration program. In 2008, the Board approved several amendments to the ORRI Plan which included the following: (i) leasehold acreage in which the Company held less than a 73% net revenue interest would not be included in the program and no overriding royalty interest revenue distributions would be made from such properties; (ii) leasehold acreage acquired for the pursuit of unconventional, resource type plays would be considered an acquisition of probable reserves rather than an Exploratory Prospect under the ORRI Plan and therefore, except as provided for in (iii), not subject to the overriding royalty interest distribution provided for in the ORRI Plan, and (iii) the Company could award up to a 1% overriding royalty interest in an unconventional resource play to the Senior Vice

President Exploration and any other participants it deems appropriate up to a maximum of 0.0125% per participant.

During fiscal 2008, the amount of $43,045 was paid to Mr. Atkins pursuant to the ORRI Plan.

Severance Benefits

Each of the employment agreements to which most of our executive officers are subject provide for severance and change of control payments upon a termination or change of control. Payments that are payable upon a termination or change of control are included in the respective employment agreement between the executive officer and the Company. The Company believes that the executive officers should be provided an incentive to consummate a change of control that would generate attractive returns for our stockholders. Without such an incentive, the executive officers may not diligently pursue such opportunities. In addition, severance provisions were included as a means of attracting and retaining executives and to provide replacement income if their employment is terminated because of a termination, except in certain circumstances. Each employment agreement contains similar but not identical provisions regarding payments upon termination or change of control and relevant provisions of those agreements are provided in the section titled Potential Payments upon Termination or Change of Control.

Other Benefits

In addition to base salaries, incentive compensation, equity awards, overriding royalty interest plan compensation and severance benefits, we provide other forms of compensation that are periodically reviewed by the Compensation Committee. Except as otherwise indicated, these benefits are available to all employees, including our named executive officers, and are offered for the purpose of providing competitive compensation and benefits to attract new employees and secure the continued employment of current employees.

401(k) Plan. We have a defined contribution 401(k) Plan that is designed to assist our executive officers and employees in providing for their retirement. Effective June 1, 2008, upon the recommendation of the Compensation Committee, the Board approved an amendment to the Company s 401(k) Plan to provide for 100% matching of each participant s deferral contributions up to 6% of the participant s compensation. In order to maintain the safe-harbor non-discrimination provisions of the 401(k) Plan, in lieu of 100% matching during the second half of 2008 the Company made a one-time discretionary contribution to the 401(k) Plan for each participant during December 2008. Effective January 1, 2009, the Company began matching 100% of each participant s deferral contributions up to 6% of the participant s compensation.

Health and Welfare Benefits. As with all of our employees generally, our executive officers are eligible to participate in medical, dental, vision, life insurance and accidental death and disability to meet their health and welfare needs. These benefits are provided so as to assure that we are able to maintain a competitive position in terms of attracting and retaining officers and other employees. This is a fixed component of compensation and the benefits are provided on a non-discriminatory basis to all of our employees.

Perquisites and Other Personal Benefits. We believe that the total mix of compensation and benefits provided to our executive officers is competitive and perquisites should generally not play a large role in our executive officers total compensation. As a result, the perquisites and other personal benefits we provide to our executive officers are limited and typically do not exceed $10,000 per person in any fiscal year.

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Other Matters

Tax and Accounting Treatment of Executive Compensation Decisions

We consider the anticipated tax treatment of our executive compensation program when setting levels and types of compensation. Section 162(m) of the Code generally disallows a tax deduction to public companies for compensation in excess of $1.0 million per person paid in any year to a company s chief executive officer or any of its three other most highly compensated executive officers (other than the chief financial officer and the chief executive officer), with certain performance-based compensation being specifically exempt from this deduction limit. During fiscal 2007 and 2008, none of our employees subject to this limit received Section 162(m) compensation in excess of $1.0 million. Consequently, the requirements of Section 162(m) did not affect the tax deductions available to us in connection with our senior executive compensation program for fiscal 2007 and 2008.

We account for stock-based awards based on their grant date fair value, as determined under GAAP. In connection with its approval of stock-based awards, the Compensation Committee is cognizant of and sensitive to the impact of such awards on stockholder dilution. The Compensation Committee also endeavors to avoid stock-based awards made subject to a market condition, which may result in an expense that must be marked to market on a quarterly basis. The accounting treatment for stock-based awards does not otherwise impact the Compensation Committee s compensation decisions.

Stock Ownership Guidelines and Hedging Prohibition

We do not currently have ownership requirements or a stock retention policy for our named executive officers. We do not have a policy that restricts our executive officers from limiting their economic exposure to our stock. We will continue to periodically review best practices and re-evaluate our position with respect to stock ownership guidelines and hedging prohibitions.

Summary Compensation

The following table sets forth the aggregate compensation awarded to, earned by or paid to our named executive officers for services rendered in all capacities during the fiscal years ended December 31, 2006, 2007 and 2008.

Summary of Compensation Table for the Fiscal year Ended December 31, 2008

ame and rincipal Position	Year	Salary ($)	Bonus[1] ($)	Stock Awards[2] ($)	Option Awards[3] ($)	Non-Equity Incentive Plan Compensation[4] ($)	All Other Compensation[5] ($)	Total ($)
llan D. Keel	2008	370,000		153,553	2,471,160		12,376	3,007,089
hief Executive	2007	240,000	100,000	73,282	2,153,250	105,600	9,600	2,681,732
fficer and President	2006	240,000		25,000	2,009,700	72,000	2,400	2,349,100
. Joseph Grady	2008	340,000		112,435	823,720		15,500	1,291,655
enior Vice President	2007	220,000	100,000	70,367	717,750	96,800	8,800	1,213,717
nd Chief Financial Officer	2006	220,000		22,919	669,900	66,000	29,641[6]	1,008,460
racy Price	2008	200,000		112,435	590,105		9,708	912,248
enior Vice President	2007	185,000	50,000	54,469	580,498	70,300	7,400	947,667

and/Business Development	2006	185,000	11,600	11,562	522,448	44,400	1,850	776,860
ay S. Mengle	2008	220,000		102,435	295,052		10,483	627,970
enior Vice President	2007	180,000	100,000	54,031	290,249	64,800	8,000	697,080
ngineering	2006	180,000	20,000	11,250	261,224	54,000	1,800	528,274
ommy H. Atkins	2008	200,000		100,636	251,122		52,129(7)	603,887
enior Vice President	2007	180,000	40,000	54,031	247,249	43,200	7,200	571,680
xploration	2006	180,000		11,250	222,524	75,600	1,800	491,174

(1) For a description of the amounts included in this column, see Compensation Discussion and Analysis Elements of Our Executive Compensation Program Discretionary Cash Incentive Compensation.

(2) Includes the dollar amount of compensation expense we recognized for the fiscal years ended December 31, 2008, 2007 and 2006 in accordance with GAAP. Pursuant to SEC rules and regulations, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. These amounts reflect our accounting expense for these awards, and do not correspond to the actual value that will be recognized by our executive officers. Assumptions used in the calculation of these amounts are included in Note 6 to our audited financial statements included in our Annual Reports on Form 10-K for the fiscal years ended December 31, 2008, 2007 and 2006, as applicable. The awards for which compensation expense was recognized consist of awards granted on August 1, 2007 and March 1, 2006. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards.

(3) Includes the dollar amount of compensation expense we recognized for the fiscal years ended December 31, 2008, 2007 and 2006 in accordance with GAAP. Pursuant to SEC rules and regulations, the amounts shown exclude the impact of estimated forfeitures related to service-based vesting conditions. These amounts reflect our accounting expense for these awards, and do not correspond to the actual value that will be recognized by our executive officers. Assumptions used in the calculation of these amounts are included in Note 13 to our audited financial statements included in our Annual Reports on Form 10-K for the fiscal years ended December 31, 2008, 2007 and 2006, as applicable. The awards for which compensation expense was recognized consist of awards granted on February 28, 2005 for Messrs. Keel and Grady and April 1, 2005 for Messrs. Price, Mengle and Atkins. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table below for a description of the material features of these awards. No options were granted to our executive officers in fiscal 2008, 2007 or fiscal 2006.

(4) For a description of the amounts included in this column, see Compensation Discussion and Analysis Elements of Our Executive Compensation Program Performance-Based Cash Incentive Compensation.

(5) Except as otherwise noted, these amounts represent 401(k) plan matching contributions during fiscal 2008, 2007 and 2006.

(6) Pursuant to his employment contract, Mr. Grady was reimbursed a total of $27,441 for commuting costs incurred by him prior to his relocation to Houston, Texas in late 2006. Reimbursements were for temporary housing and air fare. In addition, we contributed $2,200 to Mr. Grady s 401(k) plan during fiscal 2006.

(7) Mr. Atkins was paid $43,045 pursuant to the Company s ORRI Plan during 2008. For a description of the amounts included in this column, see Compensation Discussion and Analysis Elements of Our Executive Compensation Program Overriding Royalty Interest Plan Compensation. Mr. Atkins also received a contribution from us of $9,084 to his 401(k) plan for the fiscal year.

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Grants of Plan-Based Awards for Fiscal Year 2008

The following table provides information concerning each grant of an award made to our named executive officers under any plan, including awards, if any, that have been transferred during the fiscal year ended December 31, 2008.

			Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
Name	Grant Date	Approval Date	Threshold ($)[2]	Target ($)	Maximum ($)	(#)[3]	($)
Allan D. Keel	9/8/08	8/15/08	185,000	314,500	444,000	270,000	2,470,500
E. Joseph Grady	9/8/08	8/15/08	170,000	289,000	408,000	90,000	823,500
Tracy Price	9/8/08	8/15/08	80,000	140,000	200,000	90,000	823,500
Jay S. Mengle	9/8/08	8/15/08	88,000	154,000	220,000	45,000	411,750
Thomas H. Atkins	9/8/08	8/15/08	80,000	140,000	200,000	38,350	350,903

(1) For the fiscal year ending December 31, 2008, the amounts included in the threshold, target and maximum columns represent, assuming the attainment of the appropriate targeted performance goals, 50%, 85% and 120%, respectively, of the annual base salaries for Messrs. Keel and Grady and 40%, 70% and 100%, respectively, of the annual base salaries for Messrs. Price, Mengle and Atkins.

(2) Under our performance-based cash incentive compensation plan, this category is referred to as the minimum payout level.

(3) The executive officers elected to exchange substantially vested stock options with an exercise price of $17.00 per share for unvested restricted stock at the rate of two stock options for one share of restricted stock.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The following is a discussion of material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and the Grants of Plan-Based Awards Table.

Employment Agreements

The Company has entered into amended and restated employment agreements with its executive officers during 2008. The compensation provisions of the employment agreements were designed with input from Longnecker & Associates and ECI and contain a compensation package designed to motivate and retain the executive officers.

Between December 29 and 31, 2008, the Company entered into amended and restated employment agreements with each of its named executive officers.

The agreements were entered into to, among other things, modify provisions relating to the federal income tax treatment of certain arrangements in order to meet the December 31, 2008 deadline for compliance with Section 409A of the Code, reflect market-based changes in compensation approved in mid-2008 by the Compensation Committee and the Board and provide for new terms of the agreements, since the initial terms of the existing employment agreements expired. In addition, the amended and restated employment agreements were entered into to provide an incentive for consistent, longer-term performance and achievement of strategic objectives to compensate our named executives for the value of their contributions, provide total compensation that is flexible enough to respond to changing market conditions and that aligns compensation with performance and provides total compensation that will motivate and retain our executive officers, support an internal culture of Company loyalty and dedication to the Company s interests.

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The agreements entered into with Messrs. Keel and Grady each provide for a term of three years and the agreements entered into with Messrs. Mengle, Atkins and Price each provide for a term of two years. Each agreement provides for automatic yearly extensions of the term, after the initial term, unless the Company or the officer elects not to extend the agreement.

Each agreement provides for a base salary (which is subject to increase at the discretion of the Company s Board or a committee thereof) and participation in the Company s Annual Cash Incentive Bonus Plan and LTIP. The initial base salaries of each executive are as follows: Mr. Keel, $370,000; Mr. Grady, $340,000; Mr. Mengle, $220,000; Mr. Atkins, $200,000; and Mr. Price, $200,000.

Under the Company s Annual Cash Incentive Bonus Plan, the executives are eligible to receive cash bonuses contingent upon attainment of annual personal and corporate goals established by the Board of the Company or a committee thereof. The agreements entered into with Messrs. Keel and Grady provide that each executive is eligible to receive a bonus based upon minimum, target and maximum award levels of no less than 50%, 85% and 120%, respectively, of such executive s base salary, and the agreements entered into with Messrs. Mengle, Atkins and Price provide that each executive is eligible to receive a bonus based upon minimum, target and maximum award levels of no less than 40%, 70% and 100%, respectively, of such executive s base salary. No cash awards are paid under this plan if the criteria for at least the minimum award level are not met.

Under the Company s LTIP, the executives are eligible to receive stock options and restricted stock awards contingent upon attainment of annual personal and corporate goals established by the Board of the Company or a committee thereof. The agreement entered into with Mr. Keel provides that he is eligible to receive an equity award based upon minimum, target and maximum award levels of no less than 75%, 225% and 450%, respectively, of his base salary; the agreement entered into with Mr. Grady provides that he is eligible to receive an equity award based upon minimum , target and maximum award levels of no less than 75%, 175% and 350%, respectively, of his base salary; and the agreements entered into with Messrs. Mengle, Atkins and Price provide that each executive is eligible to receive an equity award based upon minimum, target and maximum award levels of no less than 50%, 150% and 300%, respectively, of such executive s base salary. The equity awards to each executive for a year shall consist of 50% restricted stock awards and 50% stock options, each subject to vesting over four years. No equity awards are granted under this plan if the criteria for at least the minimum award level are not met.

The employment agreements also contain provisions for payment of severance benefits upon termination of employment. A discussion of applicable severance benefits is provided below under Potential Payments upon Termination or Change of Control.

Stock Awards

In August 2007, Messrs. Keel, Grady, Price, Mengle and Atkins were each awarded 50,000 shares of restricted common stock that vest over a four year period in annual increments commencing August 1, 2008, according to the following schedule: 33% (year 1), 23% (year 2), 22% (year 3) and 22% (year 4). These awards were made in partial compensation for their efforts in consummating the EXCO acquisition and in recognition of the need to adjust executive officer compensation in order to be competitive with salaries being paid to similarly-situated oil and gas executives. The closing price of our common stock on the date of grant was $7.35 per share.

All of our named executive officers elected in September 2008 to exchange their substantially vested options exercisable at $17.00 per share for half as many shares of unvested restricted stock. See Executive Compensation Compensation Discussion and Analysis Elements of Our Executive Compensation Program Long-Term Equity Based Incentive Compensation.

On March 4, 2009, the Compensation Committee approved the bonus award of restricted Company common stock to Messrs. Keel, Grady, Mengle, Price and Atkins and other participating Company employees pursuant to the Company s LTIP for the fiscal year ending December 31, 2008.

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Mr. Keel received approval for 123,459 shares, Mr. Grady received approval for 89,799 shares, Mr. Mengle received approval for 47,827 shares, Mr. Price received approval for 44,312 shares and Mr. Atkins received approval for 44,321 shares. As all executive officers elected not to accept a cash award pursuant to the Company s Annual Cash Incentive Bonus Plan for the 2008 fiscal year, the Board, upon the recommendation of the Compensation Committee, elected to award bonuses earned for 2008 under the LTIP in the form of unvested restricted shares of common stock only, rather than 50% in unvested restricted stock and 50% in unvested stock options. These stock awards will vest 25% per year, over the first through fourth anniversaries from the date of grant, at which time 100% of the stock awards will be vested. As the executives voluntarily agreed to give up additional cash compensation, the Compensation Committee believed it appropriate that the executives receive such equity grants in lieu of cash, which the Compensation Committee believed would also act as a long-term retention tool and better align employee and stockholder interests.

Option Awards

On February 28, 2005, we entered into stock option agreements with Messrs. Keel and Grady in conjunction with their commencement of employment with us. Mr. Keel received options to purchase 270,000 shares of our common stock at an exercise price of $9.70 per share, options to purchase 405,000 shares of our common stock at an exercise price of $12.50 per share and options to purchase 540,000 shares of our common stock at an exercise price of $17.00 per share. Mr. Grady received options to purchase 90,000 shares of our common stock at an exercise price of $9.70 per share, options to purchase 135,000 shares of our common stock at an exercise price of $12.50 per share and options to purchase 180,000 shares of our common stock at an exercise price of $17.00 per share.

On April 1, 2005, we entered into stock option agreements with Messrs. Price, Mengle and Atkins in conjunction with their commencement of employment with us. Mr. Price received options to purchase 90,000 shares of our common stock at an exercise price of $11.60 per share and options to purchase 180,000 shares of our common stock at an exercise price of $17.00 per share. Mr. Mengle received options to purchase 45,000 shares of our common stock at an exercise price of $11.60 per share and options to purchase 90,000 shares of our common stock at an exercise price of $17.00 per share. Mr. Atkins received options to purchase 38,300 shares of our common stock at an exercise price of $11.60 per share and options to purchase 76,700 shares of our common stock at an exercise price of $17.00 per share.

The options vest with respect to 15% of the shares on the first anniversary of the grant date and thereafter at the end of each full succeeding year from the grant date according to the following schedule: 25% on the second anniversary, 25% on the third anniversary and 35% on the fourth anniversary of the grant date.

All of our named executive officers elected in September 2008 to exchange their substantially vested options exercisable at $17.00 per share for half as many shares of unvested restricted stock. See Compensation Discussion and Analysis Elements of Our Executive Compensation Program Long-Term Equity Based Incentive Compensation.

Salary and Cash Incentive Awards in Proportion to Total Compensation

The following table sets forth the percentage of each named executive officer s total compensation that we paid in the form of base salary and annual cash incentive awards.

Name	Year	Percentage of Total Compensation Paid in Base Salary and Annual Incentive Awards
Allan D. Keel	2008	12.30%
	2007	16.62%
	2006	13.28%
E. Joseph Grady	2008	26.32%
	2007	34.34%
	2006	28.36%
Tracy Price	2008	21.92%
	2007	32.22%
	2006	29.53%
Jay S. Mengle	2008	35.03%
	2007	49.46%
	2006	44.30%
Tommy H. Atkins	2008	33.12%
	2007	46.04%
	2006	52.04%

Outstanding Equity Awards Value at 2008 Fiscal Year-End

The following table provides information concerning unexercised options, stock that has not vested, and equity incentive plan awards for our named executive officers as of December 31, 2008.

Outstanding Equity Awards as of December 31, 2008(6)

	Option Awards				Stock Awards	
Name	Number of Securities Underlying Unexercised Options (#) Exercisable(1)	Number of Securities Underlying Unexercised Options (#) Unexercisable(2)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(5)
Allan D. Keel	175,000	94,500	9.70	2/28/2015	33,500(3)	103,850
	263,250	141,750	12.50	2/28/2015	270,000(4)	837,000
E. Joseph Grady	58,500	31,500	9.70	2/28/2015	33,500(3)	103,850
	87,750	47,250	12.50	2/28/2015	90,000(4)	279,000
Tracy Price	58,500	31,500	11.60	4/1/2015	33,500(3)	103,850

					90,000(4)	279,000
Jay S. Mengle	29,250	15,750	11.60	4/1/2015	33,500(3)	103,850
					45,000(4)	139,500
Thomas H. Atkins	24,895	13,405	11.60	4/1/2015	33,500(3)	103,850
					38,350(4)	118,885

(1) The exercisable but unexercised options vested on the first, second, and third anniversary dates of the date of grant. For Messrs. Keel and Grady the vesting dates were February 28th of 2006, 2007, and 2008 and April 1st of 2006, 2007, and 2008 for Messrs. Price, Mengle and Atkins.

(2) The underlying securities of unexercised and unexercisable options vest on the fourth anniversary of the date of grant. For Messrs. Keel and Grady the initial date of grant was February 28, 2005 with a corresponding 100% vesting date on February 28, 2009 and for Messrs. Price, Mengle and Atkins the initial date of grant was April 1, 2005 with a corresponding 100% vesting date of April 1, 2009. All of our named executive officers elected in September 2008 to exchange all unexercised options which had an exercise price of $17.00 per share for half as many shares of restricted stock. See Compensation Discussion and Analysis Long-Term Equity Based Incentive Compensation.

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(3) The restricted stock awards reflected in this row vest over a four year period in annual increments commencing August 1, 2008, according to the following schedule: 33% (year 1), 23% (year 2), 22% (year 3) and 22% (year 4).

(4) The restricted stock awards reflected in this row vest over a five year period in annual increments commencing September 8, 2009, according to the following schedule: 12.5% (year 1), 12.5% (year 2), 12.5% (year 3), 12.5% (year 4) and 50.0% (year 5).

(5) The market value of the unvested restricted stock was determined using the closing price of our common stock on December 31, 2008 of $3.10 per share.

(6) Upon a change in control, all unvested equity awards held by the named executive officers will become vested and, in the case of options, exercisable. See Potential Payments upon Termination or Change of Control Severance Payments.

Option Exercises and Stock Vested in Fiscal Year 2008

The following table provides information concerning each vesting of stock, including restricted stock, restricted stock units and similar instruments, during the fiscal year ended December 31, 2008 on an aggregated basis with respect to each of our named executive officers. During this time, no named executive officers exercised any stock option awards.

Option Exercises and Stock Vested
During the Fiscal Year Ended December 31, 2008

		Stock Awards	
Name		**Number of Shares Acquired on Vesting (#)**	**Value Realized on Vesting ($)**
Allan D. Keel	2008	16,500	200,475(1)
E. Joseph Grady	2008	16,500	200,475(1)
Tracy Price	2008	16,500	200,475(1)
Jay S. Mengle	2008	16,500	200,475(1)
Thomas H. Atkins	2008	16,500	200,475(1)

(1) The restricted stock was issued in fiscal 2007 and vested on August 1, 2008. The value was determined using the closing price of our common stock of $12.15/share on the vesting date. Based on the $12.15 share price, 4,125 shares were withheld from each named executive officer in satisfaction of federal tax withholding obligations.

Potential Payments upon Termination or Change of Control

Payments that would have been payable to executive officers having employment agreements with us upon a termination or change of control are included in the respective employment agreement between the executive officer and the Company. Each employment agreement contains similar but not identical provisions regarding payments upon termination or change of control and relevant provisions of those agreements are described above under the Summary Compensation Table, as well as below.

Each of the employment agreements provides for severance and change of control payments in the event we terminate an officer s employment without Cause or if the officer terminates for Good Reason or due to his death or disability. The employment agreements also provide for acceleration of vesting of equity awards if we terminate an officer without Cause or if an officer terminates for Good Reason, if such awards are not subject to performance-based vesting, or upon death or disability.

Cause generally means (A) continued failure by the executive officer to perform substantially the executive s duties and responsibilities (other than a failure resulting from permanent disability) that is materially injurious to the Company and that remains uncorrected for 10 days after receipt of appropriate written notice from the Board; (B) reliable evidence of engagement in willful, reckless or grossly negligent misconduct that is materially injurious to the Company or any of its affiliates, monetarily or otherwise; (C) except as provided by (D), the indictment of the executive with a crime involving moral turpitude or a felony, provided that if the criminal charge is dismissed with prejudice or if executive is acquitted at trial or on appeal, the executive will be deemed to have been terminated without Cause; (D) the indictment of the executive with an act of criminal fraud, misappropriation or personal dishonesty, provided that if the criminal charge is subsequently dismissed with prejudice or the executive is acquitted at trial or on appeal then the executive will be deemed to have been terminated without Cause; or (E) a material breach by the executive of any provisions of the employment agreement that is materially injurious to the Company and that remains uncorrected for 10 days following written notice of such breach by the Company to the executive identifying the provision of the employment agreement that the Company determined has been breached.

Good Reason generally means one or more of the following conditions arising not more than six months before the executive s termination date without the executive s consent: (A) a material breach by the Company of any provision of the employment agreement; (B) assignment by the Board or a duly authorized committee thereof to the executive of any duties that materially and adversely alter the nature or status of the executive s position, job descriptions, duties, title or responsibilities from those of such executive officer s prior position, or eligibility for Company compensation plans; (C) requirement by the Company for the executive officer to relocate anywhere other than the greater Houston, Texas metropolitan area, except for required travel on Company business to an extent substantially consistent with his obligations under their employment agreement; (D) a material reduction in the executive officer s base salary in effect at the relevant time; or (E) exclusion of the executive officer from eligibility for the Company s active bonus or benefits plan as described above. Notwithstanding anything in the executive s employment agreement to the contrary, Good Reason will exist only if the executive provides notice to the Company of the existence of the condition otherwise constituting Good Reason within 90 days of the initial existence of the condition, and the Company fails to remedy the condition on or before the 30th day following its receipt of such notice.

Change of Control means the occurrence of any one or more of the following events:

(i) The Company is not the surviving entity in any merger, consolidation or other reorganization (or survives only as a subsidiary of any entity other than a previously wholly-owned subsidiary of the Company), or in the case of a reverse merger in which Company management and the executive officer do not assume control of the surviving entity;

(ii) The Company sells or exchanges in a single transaction or in a series of related transactions occurring in the 12-month period ending on the date of the most recent sale or exchange, assets having a gross fair market value equal to 40% or more of the total gross fair market value (determined without regard to any liabilities associated with such assets) of all of the Company s assets immediately before such transfer or transfers, to any other person or entity (other than to (A) an entity controlled by the Company immediately after the transfer, (B) a shareholder of the Company (immediately before the transfer) in exchange for or with respect to its stock, (C) a person or entity that directly or indirectly owns 50% or more of the total value or voting power of all outstanding stock of the Company immediately after the transfer, (D) an entity, 50% or more of the total value or voting power of which is directly or indirectly owned by the Company immediately after the transfer);

(iii) Any person or entity, including a group as contemplated by Section 13(d)(3) of the Securities Exchange Act of 1934, as amended, other than Oaktree Capital Management, L.P. or its affiliates, or any other person, entity or group that is considered to own more than 50% of the outstanding shares of the Company s voting stock (based upon voting power), acquires or gains ownership or control (including, without limitation, power to vote) of more than 50% of the outstanding shares of the Company s voting stock (based upon voting power); or

(iv) As a result of or in connection with a contested election of directors, a majority of members of the Board is replaced by directors whose election is not endorsed by a majority of members of the Board before the date of the election.

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Severance Payments

Assuming termination or a change of control of the Company on December 31, 2008, each named executive officer would have been entitled to the payments provided below. These numbers could not be determined with any certainty unless or until the applicable scenario below actually occurred, thus the amounts are solely estimates and the actual payout to each executive officer in the event of one of these scenarios below is subject to change.

Name	Termination By Employee Without Good Reason	Termination For Cause	Termination By Employee For Good Reason[4,5,7]	Termination Without Cause[4,5,7]	Termination Upon Change of Control[4,5,7]	Death or Permanent Disability[6]	Change in Control[8]
Allan D. Keel							
Severance Payments[1,3]			$ 1,422,044	$ 1,422,044	$ 1,422,044	$ 1,110,000	$
Health Insurance Continuation[9]			76,256	76,256	76,256	76,256	
Unvested & Accelerated							
Restricted Stock Units			303,500	303,500	303,500	303,500	303,500
Stock Options						675,000	675,000
E. Joseph Grady							
Severance Payments[1,3]			$ 1,306,032	$ 1,306,032	$ 1,306,032	$ 1,020,000	$
Health Insurance Continuation[9]			76,256	76,256	76,256	76,256	
Unvested & Accelerated							
Restricted Stock Units			123,500	123,500	123,500	123,500	123,500
Stock Options						225,000	225,000
Tracy Price							
Severance Payments[2,3]			$ 540,600	$ 540,600	$ 540,600	$ 400,000	$
Health Insurance Continuation[9]			50,837	50,837	50,837	50,837	
Unvested & Accelerated							
Restricted Stock Units			123,500	123,500	123,500	123,500	123,500
Stock Options						90,000	90,000
Jay S. Mengle							
Severance Payments[2,3]			$ 569,600	$ 569,600	$ 569,600	$ 440,000	$
Health Insurance Continuation[9]			38,081	38,081	38,081	38,081	
Unvested & Accelerated							
Restricted Stock Units			78,500	78,500	78,500	78,500	78,500
Stock Options						45,000	45,000
Tommy H. Atkins							
Severance Payments[2,3]			$ 486,400	$ 486,400	$ 486,400	$ 400,000	$
Health Insurance Continuation[9]			50,837	50,837	50,837	50,837	
Unvested & Accelerated							
Restricted Stock Units			71,850	71,850	71,850	71,850	71,850

Stock Options	38,300	38,300

(1) In the event the employment of Messrs. Keel and Grady is terminated by the Company without Cause or by them for Good Reason, and subject to their observance of certain non-compete and release of liability agreements, each will receive a severance payment consisting of (i) a cash amount equal to 2.99 times the sum of the current calendar year s Base Salary and the prior year s Annual Cash Incentive Bonus, (B) health insurance benefits for 36 months from the termination date at no charge to the executive, and (C) acceleration to 100% vested status for all stock, stock options and other equity awards to the extent such awards (other than stock options and stock appreciation rights) are not subject to performance-based vesting for purposes of qualifying as performance-based compensation for purposes of Section 162(m) of the Code. Had the employment of Messrs. Keel and Grady been terminated by the Company without Cause or by them for Good Reason in 2008, Mr. Keel would have been paid $1,442,044 and Mr. Grady would have been paid $1,306,032 plus the value of health insurance benefits for three years from the termination date, estimated at $25,419 per year.

(2) In the event the employment of Messrs. Price, Mengle and Atkins is terminated by the Company without Cause or by them for Good Reason, and subject to their observance of certain non-compete and release of liability agreements, each will receive a severance payment consisting of (i) a cash amount equal to 2 times the sum of the current calendar year s Base Salary and the prior year s Annual Cash Incentive Bonus, (B) health insurance benefits for 24 months from the termination date at no charge to the executive, and (C) acceleration to 100% vested status for all stock, stock options and other equity awards to the extent such awards (other than stock options and stock appreciation rights) are not subject to performance-based vesting for purposes of qualifying as performance-based compensation for purposes of Section 162(m) of the Code. Had the employment of Messrs. Price, Mengle and Atkins been terminated by the Company without Cause or by them for Good Reason in 2008, Mr. Price would have been paid $540,600, Mr. Mengle would have been paid $569,600 and Mr. Atkins would have been paid $486,400 plus the value of health insurance benefits for two years from the termination date, estimated at $25,419 per year for Messrs. Price and Atkins and $19,040 per year for Mr. Mengle.

(3) If no annual cash incentive bonus was paid to Messrs. Keel and Grady for the year before the year in which such officer s employment was terminated, if termination was by the Company without Cause or by the executive officer for Good Reason, Messrs. Keel and Grady are entitled to receive 2.99 times the amount of discretionary bonuses paid to such officer, and Messrs. Mengle, Price and Atkins are entitled to receive 2 times the amount of discretionary bonuses paid to such officer within the 12 month period preceding termination. Because an Annual Cash Incentive Bonus was paid to all the executive officers for 2007 in 2008, the applicable columns do include such Annual Cash Incentive Bonus.

(4) If not in connection with a Change of Control, the Company terminates the executive officer s employment without Cause or the officer terminates his employment for Good Reason, the executive officer will receive half of the cash severance amount in a lump sum within 15 days of his termination date and half the number of months of health insurance benefit continuation. The executive officer will not be entitled to the remainder of the cash severance payment, and the remaining number of months of health insurance continuation, unless the executive officer gives notice to the Company within 30 days before conclusion of 50% of the Non-Compete Term that he agrees, for the remainder of the Non-Compete Term to comply with the non-compete and non-solicitation provisions of such officer s respective employment agreement. In such event, the executive officer will receive the remainder of his cash severance payment and an extension of his health insurance benefits for 18 months for Messrs. Keel and Grady and 12 months for Messrs. Mengle, Price and Atkins payable in a lump sum within 15 days after the date of conclusion of 50% of the Non-Compete Term.

(5) Under each executive officer s stock option agreements and restricted stock awards under our 2005 Stock Incentive Plan, in the event of a Change of Control, termination by the Company without Cause or termination by the executive officer for Good Reason, each executive officer s unvested options and unvested restricted stock will become fully vested and, in the case of options, exercisable with respect to 100% of such shares, resulting in the vesting of 539,750 shares for Mr. Keel, 202,250 shares for Mr. Grady, 155,000 shares for Mr. Price, 94,250 shares for Mr. Mengle and 85,255 shares for Mr. Atkins. As of December 31, 2008, the aggregate value of the option shares held by the executive officers was $0.00 as the closing price of the Company s common stock on that date was less than the weighted average exercise price of the stock options.

(6) In the event of death or disability, each executive officer will be entitled to: (i) his pro rata Base Salary and pro rata Target Annual Cash Incentive Bonus through the date of termination for the year in which termination occurs, plus a lump sum amount equal to the greater of: (1) the remainder of the base salary that would have been earned by the executive officer under the executive s employment agreement between the date of his death or permanent disability and the expiration of the then current term of the employment agreement, or (2) 12 months of base salary plus the executive s Target Annual Cash Incentive Bonus for the year of termination; and (ii) full

acceleration of vesting for all stock, stock option and other equity awards. Such an event would result in the vesting of

539,570 shares for Mr. Keel, 202,250 shares for Mr. Grady, 155,000 shares for Mr. Price, 94,250 shares for Mr. Mengle and 85,255 shares for Mr. Atkins. As of December 31, 2008, the aggregate value of the option shares was $0.00, as the closing price of the Company s common stock on that date was less than the weighted average exercise price of the stock options.

(7) If the severance payment is made as a result of termination by the Company without Cause or by the Employee for Good Reason within 12 months after a Change of Control, the Company will pay the entire cash severance amount in a lump sum on the executive officer s date of termination.

(8) Upon a change in control, each executive officer s unvested options and unvested restricted stock will become fully vested and, in the case of options, exercisable with respect to 100% of such shares, resulting in the vesting of 539,750 shares for Mr. Keel, 202,250 shares for Mr. Grady, 155,000 shares for Mr. Price, 94,250 shares for Mr. Mengle and 85,255 shares for Mr. Atkins. As of December 31, 2008, the aggregate value of the option shares held by the executive officers was $0.00 as the closing price of the Company s common stock on that date was less than the weighted average exercise price of the stock options. For all the shares of restricted stock granted on or before December 31, 2008, acceleration of vesting will occur upon a Change in Control as defined in the Company s 2005 Stock Incentive Plan, rather than a Change of Control as defined in the applicable employment agreement. Under the 2005 Stock Incentive Plan, Change in Control means (a) the direct or indirect sale, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets of the Company to any person (as that term is used in Section 13(d)(3) of the Exchange Act) other than Oaktree Holdings or its affiliates; (b) the adoption of a plan relating to the liquidation or dissolution of the Company; (c) the consummation of any transaction (including, without limitation, any merger or consolidation) the result of which is that any person or group (as such terms are used in Section 13(d) of the Exchange Act) other than Oaktree Holdings or its affiliates, becomes the beneficial owner directly or indirectly of more than 50% of the voting power of the Company; or (d) incumbent directors cease for any reason to constitute at least a majority of the Board, excluding certain reincorporation or holding company transactions or a public offering resulting in the Company being listed or approved for listing on a national securities exchange.

(9) If the employment of Messrs. Keel or Grady is terminated by reason of death or permanent disability, the executive officer s family members that are covered by the Company group health plan may be reimbursed for group health plan continuation coverage under the Consolidated Omnibus Budget Reconciliation Act (COBRA) for up to 36 months, provided a member of the executive officer s family provides timely notice to the health plan administrator of the executive officer s death or permanent disability. If the employment of Messrs. Mengle, Price or Atkins employment is terminated by reason of death or permanent disability, the executive officer s family members that are covered by the Company group health plan may be reimbursed for group health plan continuation coverage under COBRA for up to 24 months, provided a member of the executive officer s family provides timely notice to the health plan administrator of the executive officer s death or permanent disability.

Non-Compete and Non-Solicitation Provisions

The agreements generally require that each executive officer not engage in competition with the Company in any geographic area in which the Company owns a material amount of oil, gas or other mineral properties, during the period commencing upon execution until the date ending: (A) on the date of termination if terminated by the Company for Cause, or (B) in all other cases of termination, at the end of a period of consecutive months following the date of termination equivalent to 50% of the number of months for which the executive officer is entitled to receive severance benefits assuming (if applicable) the executive officer will give the required notice as described in the employment agreement. Each executive officer is also subject to non-solicitation provisions during the term of the non-compete provisions prohibiting the executive officer from inducing or soliciting any other executive or officer of the Company to terminate their employment with the Company.

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Gross Up Payments

Pursuant to the respective employment agreements, if it is determined that any payment, award, benefit or distribution (or an acceleration of any payment, award, benefit or distribution) to an executive officer by the Company or by another entity in the event of a Change of Control is subject to the imposition of an excise tax imposed by Section 4999 of the Code, or any interest or penalties are incurred by the executive officer with respect to such excise tax, the Company will pay the executive officer an additional payment in an amount equal to that required to result in the executive officer receiving, after application of the excise tax, a net amount that would have been received hereunder had the excise tax not applied.

Equity Compensation Plan Information

The following table shows our stockholder approved and non-stockholder approved equity compensation plans as of December 31, 2008:

Plan Category (a)(b)(c)	**Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights**	**Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights**	**Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))**
Equity compensation plans approved by security holders	1,663,540	$ 10.39	1,509,720
Total	1,663,540	$ 10.39	1,509,720

Our two equity compensation plans with outstanding options that have been approved by our stockholders to-date are our (i) 2004 Stock Option and Compensation Plan and (ii) Amended and Restated 2005 Stock Incentive Plan (2005 Plan). Although we sought and obtained stockholder approval of the 2004 Stock Option and Compensation Plan, neither the plan itself nor the outstanding grants were contingent on stockholder approval. The Company s 1994 Employee Stock Option Plan has no outstanding options available for conversion to common stock and there are no outstanding warrants that may be converted to common stock.

As of December 31, 2008, we had issued options for 1,619,240 shares of common stock at a weighted-average exercise price of $10.53 per share under our 2005 Plan. As of December 31, 2008, the aggregate number of shares of our common stock that may be issued and outstanding pursuant to the exercise of awards under our 2005 Plan may not exceed 3,852,500 shares, reduced by 153,500 shares (the number of shares of outstanding options and awards granted under the 2004 Stock Option and Compensation Plan, unless and to the extent such options and awards are cancelled or forfeited). As of December 31, 2008, awards covering a total of 1,509,720 shares of common stock were currently available to be issued under our 2005 Plan. However, on March 4, 2009, the Compensation Committee approved the award of shares of restricted common stock and stock options to Company employees pursuant to the Company s LTIP for the fiscal year ending December 31, 2008. A total of 648,936 shares of unvested restricted common stock and stock options for 488,660 shares of common stock have been approved for issuance pursuant to the LTIP for the fiscal year 2008. During the first quarter 2009, 45,000 shares of stock options granted under the 2005 Plan were forfeited as a result of employees leaving the employment of the Company prior to full vesting of the option shares and the employees not timely exercising their option rights pursuant to their respective stock option award agreements. Pursuant to the provisions of the 2005 Plan the forfeited shares were available for issuance under the 2005 Plan. As a result, the Company has 417,037 shares available to be awarded pursuant to the 2005 Plan as of April 9, 2009.

There are options outstanding for 44,300 shares of common stock with a weighted-average exercise price of $4.90 per share under the 2004 Stock Option Compensation Plan. There are no outstanding options issued under the 1994 Employee Stock Option Plan as all options have either been exercised or have expired.

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PRINCIPAL STOCKHOLDERS

The following table sets forth information as of November 10, 2009 (or, with respect to the accrued dividends on the Series G Preferred Stock convertible into common stock, September 30, 2009) regarding the beneficial ownership of common stock by each person known to us to own beneficially 5% or more of the outstanding common stock, each director, certain named executive officers, and the directors and executive officers as a group. The persons named in the table have sole voting and investment power with respect to all shares of common stock owned by them, unless otherwise noted.

Beneficial ownership is determined in accordance with the rules of the SEC. For the purpose of calculating the number of shares beneficially owned by a stockholder and the percentage ownership of that stockholder, shares of common stock subject to options that are currently exercisable or exercisable within 60 days of the date of this prospectus by that stockholder are deemed outstanding.

Name and Address of Beneficial Owner	Title of Class	Amount and Nature of Beneficial Ownership	Percent %
Allan D. Keel(1,2)	Common	1,177,126	16.48
	Series G	600	*
E. Joseph Grady(2,3)	Common	458,008	6.89
Tracy Price(2,4)	Common	273,887	4.21
Jay S. Mengle(2,5)	Common	213,902	3.31
Thomas H. Atkins(2,6)	Common	170,446	2.64
B. James Ford(7,8)	Common		*
Adam C. Pierce(7,8)	Common		*
Lee B. Backsen(2,13)	Common	16,292	*
Lon McCain(2,13)	Common	16,292	*
All current directors and officers as a group (9 persons)(9)	Common	2,325,953	30.84
	Series G	600	*
Oaktree Capital Management, LLC(8,10)	Common	8,734,839	66.38
	Series G	76,710	95.29
	Series H	2,000	90.91
J. Virgil Waggoner(11,12)	Common	425,333	6.62

* Denotes less than 1% of class beneficially owned.

(1) Reported common stock includes 454,334 shares held directly, 47,792 shares underlying convertible preferred stock, and options to acquire 675,000 shares of common stock that vested as follows: 101,250 shares on February 28, 2006, 168,750 shares on February 28, 2007, 168,750 shares on February 28, 2008 and 236,250 shares that vested on February 28, 2009. In connection with this offering, we anticipate that the number of shares into which the convertible preferred stock will convert will increase by shares, assuming an offering price of $ per share, which is the midpoint of the range provided on the cover page of this prospectus.

(2) Stockholder s current address is 717 Texas Avenue, Suite 2900, Houston, Texas 77002.

(3) Reported common stock includes 233,008 shares held directly and options to acquire 225,000 shares of common stock that vested as follows: 33,750 shares on February 28, 2006, 56,250 shares on February 28, 2007, 56,250 shares on February 28, 2008 and 78,750 shares on February 28, 2009.

(4) Reported common stock includes 183,887 shares held directly and options to acquire 90,000 shares of common stock that vested as follows: 13,500 shares on April 1, 2006,

22,500 shares on April 1, 2007 and 22,500 shares on April 1, 2008 and 31,500 shares that vested on April 1, 2009.

(5) Reported common stock includes 168,902 shares held directly and options to acquire 45,000 shares of common stock that vested as follows: 6,750 shares on April 1, 2006, 11,250 shares on April 1, 2007, 11,250 shares on April 1, 2008 and 15,750 shares on April 1, 2009.

(6) Reported common stock includes 132,146 shares held directly and options to acquire 38,300 shares of common stock that vested as follows: 5,745 shares on April 1, 2006, 9,575 shares on April 1, 2007, and 9,575 shares on April 1, 2008 and 13,405 shares on April 1, 2009.

(7) Excludes shares held by Oaktree Capital Management, LLC, of which Messrs. Ford and Pierce both disclaim beneficial ownership.

(8) Stockholder s address is c/o Oaktree Capital Management, LLC, 333 South Grand Avenue, Los Angeles, California 90071.

(9) Reported common stock includes 1,204,861 shares held directly, 1,073,300 shares subject to currently exercisable options, and 47,792 shares underlying convertible preferred stock.

(10) Reported common stock includes 6,736,353 shares underlying Series G and Series H convertible preferred stock (including accrued dividends on the Series G Preferred Stock) and 1,998,486 shares in each case held directly by Oaktree Holdings. OCM Principal Opportunities Fund III, L.P. (POF III) is the managing member of Oaktree Holdings and, therefore, has investment and voting control over the securities held by Oaktree Holdings. OCM Principal Opportunities Fund III GP, LLC (POF III GP) is the general partner of POF III, Oaktree Fund GP I, L.P. (GP I) is the managing member of POF III GP, Oaktree Capital I, L.P. (Capital I) is the general partner of GP I, OCM Holdings I, LLC (Holdings I) is the general partner of Capital I, Oaktree Holdings LLC (Holdings) is the managing member of Holdings I, Oaktree Capital Group, LLC (OCG) is the managing member of Holdings, Oaktree Capital Group Holdings L.P. (OCH) is the holder of a majority of the voting units of OCG, and Oaktree Capital Group Holdings GP, LLC is the general partner of OCGH. In connection with this offering, we anticipate that the number of shares into which the convertible preferred stock will convert will increase by shares, assuming an offering price of $ per share, which is the midpoint of the range provided on the cover page of this prospectus.

(11) Stockholder s address is 6605 Cypresswood Drive, Suite 250, Spring, Texas 77379.

(12) Reported common stock includes 425,333 held directly.

(13) Reported common stock includes 16,292 shares each held directly by Messrs. McCain and Backsen.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Transactions with our directors, executive officers, principal stockholders or affiliates must be at terms that are no less than favorable to us than those available from third parties and must be approved in advance by a majority of disinterested members of the Board.

There were no related party transactions during the fiscal year ending December 31, 2007 or the fiscal year ended December 31, 2008.

We expect to enter into an agreement with our principal stockholder, Oaktree Holdings, that will provide us the right, in connection with this offering, to cause Oaktree Holdings to convert all of its shares of our Series G Preferred Stock, and the accrued but unpaid dividends on such shares. We expect that number of shares of our common stock to be issued per share of preferred stock will be equal to (i) the sum of $500 plus the accrued but unpaid dividends with respect to such share divided by (ii) the lesser of $9.00 and the price to the public for our common stock received in this offering. Each $1.00 below $9.00 at which our common stock is sold in this offering will result in the issuance to holders of Series G Preferred Stock of an additional shares of our common stock per share of Series G Preferred Stock.

Pursuant to a shareholders agreement among the holders of the Series G Preferred Stock, if Oaktree Holdings elects to convert any shares of Series G Preferred Stock into common stock, all other holders must likewise convert a proportional number of shares. As a result, the shares of our Series G Preferred Stock held by our President and CEO, Allan D. Keel, will also be converted into shares of our common stock in connection with this offering.

We anticipate issuing shares of our common stock to Oaktree Holdings and shares of our common stock to Mr. Keel in connection with the conversion of our Series G Preferred Stock and the accrued but unpaid dividends on those shares, in each case assuming an offering price of $ per share, which is the midpoint in the range provided on the cover page of this prospectus.

Pursuant to the Certificate of Designations governing the terms of the Series H Preferred Stock, if Oaktree Holdings converts all of its shares of Series G Preferred Stock into common stock, all shares of Series H Preferred Stock automatically also are converted into shares of our common stock. As of September 30, 2009, Oaktree Holdings was the holder of record of 2,000 shares of our Series H Preferred Stock, all of which will be converted into shares of our common stock in connection with this offering. Our Series H Preferred Stock is convertible into that number of shares of our common stock having a value equal to $500 divided by $3.50. We anticipate issuing shares of our common stock to Oaktree Holdings in connection with the conversion of all of our Series H Preferred Stock, assuming an offering price of $ per share, which is the midpoint in the range provided on the cover page of this prospectus.

On May 13, 2009 and November 6, 2009, an affiliate of Oaktree Holdings, in its capacity as a lender under our second lien term loan agreement, entered into a second amendment and a third amendment and waiver to our second lien term loan agreement. No fees or other consideration was paid in connection with such amendments and waiver. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Second Lien Term Loan Agreement.

On November 6, 2009, we made an unsecured promissory note in aggregate principal amount equal to $10 million in favor of Wells Fargo Bank, National Association. As a condition to its willingness to advance funds to us in return for our unsecured promissory note, Wells Fargo Bank, National Association required that Oaktree Holdings provide credit support for this promissory note by depositing into escrow $10 million. Under the terms of the escrow agreement, upon the occurrence of any event of default under this promissory note, on January 10, 2010, Wells Fargo Bank, National Association may, at its option, cause this promissory note to be assigned to Oaktree Holdings and draw upon the funds in escrow as payment for the assignment. In consideration of Oaktree Holdings willingness to provide deposit into escrow $10 million as credit support for this promissory note, on November 6, 2009 we made an unsecured subordinated promissory note in aggregate principal amount equal to $2 million in favor of Oaktree Holdings.

DESCRIPTION OF CAPITAL STOCK

General

The following descriptions are summaries of material terms of our common stock, preferred stock, certificate of incorporation and bylaws. This summary is qualified by reference to our certificate of incorporation, bylaws and the designations of our preferred stock, which are filed as exhibits to the registration statement of which this prospectus forms a part, and by the provisions of applicable law.

We are authorized to issue 200.0 million shares of common stock, par value $0.001 per share. As of , 2009, assuming the completion of the Preferred Stock Conversion, there were shares of our sole class of common stock issued and outstanding and held by approximately record owners. On an as converted basis, if all of the common stock underlying granted employee stock options, outstanding at , 2009 were issued by us, the number of our outstanding shares of common stock will increase to approximately million shares.

Our common stock is traded on the OTCBB under the symbol CXPO. In connection with this offering, we have applied to list our stock on the NASDAQ Global Market under the symbol CXPO. Fidelity Transfer Company is the transfer agent for the common stock.

Our Common Stock

Voting

Holders of common stock are entitled to one vote for each share held of record on each matter submitted to a vote of stockholders, including the election of directors, and do not have any right to cumulate votes in the election of directors.

Dividends

Subject to the rights and preferences of the holders of any series of preferred stock which may at the time be outstanding, holders of common stock are entitled to receive ratably such dividends as the Board from time to time may declare out of funds legally available therefor.

Liquidation Rights

In the event of any liquidation, dissolution or winding-up of our affairs, after payment of all of our debts and liabilities and subject to the rights and preferences of the holders of any outstanding shares of any series of our preferred stock, the holders of common stock will be entitled to share ratably in the distribution of any of our remaining assets.

Other Matters

Holders of common stock have no conversion, preemptive or other subscription rights and there are no redemption rights or sinking fund provisions with respect to the common stock.

As of September 30, 2009, assuming the completion of the Preferred Stock Conversion, there were million shares of common stock, par value $0.001 per share, issued and outstanding in one class. Following this offering, approximately million shares of common stock will be held by Oaktree Holdings or its affiliates and our executive officers and directors.

Our Preferred Stock

Our Board has the authority to issue preferred stock in one or more classes or series and to fix the designations, powers, preferences and rights, and the qualifications, limitations or restrictions thereof including dividend rights, dividend rates, conversion rights, voting rights, terms of redemption, redemption prices, liquidation preferences and the number of shares constituting any class or series, without further vote or action by the stockholders. The issuance of preferred stock may have the effect of delaying, deferring or preventing a change in control of us without further action by the stockholders and may adversely affect the voting and other rights of the holders of common stock. At present, we have no plans to issue any additional shares of preferred stock.

As of September 30, 2009, there were 82,600 shares of preferred stock issued and outstanding in two series: 80,500 shares of our Series G convertible preferred stock, par value $0.01 per share, and 2,100 shares of Series H convertible preferred stock, par value $0.01 per share. Of the 80,500 shares of our Series G convertible preferred stock, 76,710 are held by Oaktree Holdings and its affiliate, and the remainder are owned by an executive officer, and nine other investors. The 2,100 shares of Series H convertible preferred stock are held of record by Oaktree Holdings, which holds 2,000 shares, and two individual investors. Our preferred stock is senior to our common stock regarding liquidation. In connection with this offering, all our outstanding Series G Preferred Stock and Series H Preferred Stock will be converted into shares of our common stock. See Prospectus Summary Preferred Stock Conversion.

Outstanding Options

At November 18, 2009, we had outstanding options for the purchase of approximately 2.0 million shares of common stock at prices ranging from $2.40 to $16.55 per share, including employee stock. If we issue additional shares, the existing stockholders percentage ownership of us may be further diluted.

Anti-Takeover Effects of Delaware Laws and Our Charter and Bylaws Provisions

Certificate of Incorporation and Bylaws. Certain provisions in our certificate of incorporation and bylaws summarized below may be deemed to have an anti-takeover effect and may delay, deter, or prevent a tender offer or takeover attempt that a stockholder might consider to be in its best interests, including attempts that might result in a premium being paid over the market price for the shares held by stockholders.

Our certificate of incorporation and bylaws contain provisions that (unless, as a general matter, a preferred stock designation provides otherwise for that series of preferred stock):

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;

- require business at special meetings to be limited to the stated purpose or purposes of that meeting;

- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and

- permit directors to fill vacancies in our board of directors.

The foregoing provisions of our certificate of incorporation and bylaws could discourage potential acquisition proposals and could delay or prevent a change of control. These provisions are intended to enhance the likelihood of continuity and stability in the composition of the board of directors and in the policies formulated by the board of directors and to discourage certain types of

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transactions that may involve an actual or threatened change of control. These provisions are designed to reduce our vulnerability to an unsolicited acquisition proposal. The provisions also are intended to discourage certain tactics that may be used in proxy fights. However, such provisions could have the effect of discouraging others from making tender offers for our shares and, as a consequence, they also may inhibit fluctuations in the market price of our common stock that could result form actual or rumored takeover attempts. Such provisions also may have the effect of preventing changes in our management.

Business Combinations. After this offering, we will be subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a business combination as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an interested stockholder as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation s voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 662/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law. This election would become effective twelve months after the adoption of the amendment and would not apply to any business combination with any person who became an interested stockholder on or before the adoption of the amendment. Section 203 of the Delaware General Corporation Law will not apply to Oaktree Holdings.

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CERTAIN UNITED STATES FEDERAL INCOME TAX CONSEQUENCES

The following general discussion summarizes certain U.S. federal income and, to a limited extent, estate tax consequences relating to the purchase, ownership and disposition of our common stock by a non-U.S. holder (as defined below). Except where noted, this summary deals only with common stock that is held as a capital asset (generally, property held for investment).

A non-U.S. holder means a beneficial owner of common stock (other than a partnership or entity treated as a partnership for U.S. federal income tax purposes) that is not for U.S. federal income tax purposes any of the following:

- an individual citizen or resident of the United States;
- a corporation or other entity taxable as a corporation created or organized under the laws of the United States, any of its states or the District of Columbia;
- an estate if its income is subject to U.S. federal income taxation regardless of the source; or
- a trust if a U.S. court is able to exercise primary supervision over administration of the trust and one or more U.S. persons have authority to control all substantial decisions of the trust, or if the trust has validly elected to continue to be treated as a domestic trust under applicable U.S. Treasury regulations.

This summary is based upon provisions of the Internal Revenue Code of 1986, as amended, or the Code, and Treasury regulations, administrative rulings and judicial decisions, all as of the date hereof. Those authorities may be changed, perhaps retroactively, so as to result in U.S. federal income and estate tax consequences different from those summarized below. This summary does not address all aspects of U.S. federal income and estate taxes and does not deal with non-U.S., state, local, alternative minimum tax or other tax considerations that may be relevant to non-U.S. holders in light of their personal circumstances. In addition, this summary does not address tax considerations applicable to investors that may be subject to special treatment under the United States federal income tax laws such as (without limitation):

- dealers in securities or foreign currency;
- tax-exempt entities;
- banks;
- thrifts;
- regulated investment companies;
- real estate investment trusts;
- traders in securities that have elected the mark-to-market method of accounting for their securities;
- controlled foreign corporations;

passive foreign investment companies;

insurance companies;

persons that hold our common stock as part of a straddle, a hedge or a conversion transaction ;

certain U.S. expatriates; and

pass-through entities for U.S. tax purposes (e.g., partnerships) or investors who hold our common stock through pass-through entities.

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If a partnership (including an entity treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership (including an entity treated as a partnership for U.S. federal income tax purposes) holding our common stock, you should consult your tax advisor.

We have not sought any ruling from the Internal Revenue Service (the IRS) with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS will agree with such statements and conclusions. **If you are considering buying our common stock, we urge you to consult your tax advisor about the particular U.S. federal, state, local and non-U.S. tax consequences of the purchase, ownership and disposition of our common stock, and the application of the U.S. federal income tax laws to your particular situation.**

Dividends

We do not presently expect to declare or pay any dividends on our common stock in the foreseeable future. However, if we do make distributions on our common stock, such distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Distributions in excess of earnings and profits will constitute a return of capital that is applied against and reduces the non-U.S. holder s adjusted tax basis in our common stock. Any remaining excess will be treated as gain realized on the sale or other disposition of our common stock and will be treated as described under Gain on Disposition of Common Stock below. Any dividend paid to a non-U.S. holder of our common stock ordinarily will be subject to withholding of U.S. federal income tax at a rate of 30%, or such lower rate as may be specified under an applicable income tax treaty, unless the dividend is effectively connected with a trade or business carried on by the non-U.S. holder within the U.S. In order to receive a reduced treaty rate, a non-U.S. holder must provide us with IRS Form W-8BEN (or applicable substitute or successor form) properly certifying eligibility for the reduced rate.

Dividends paid to a non-U.S. holder that are effectively connected with the conduct of a trade or business by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, are attributable to a permanent establishment or fixed base in the United States) generally will be exempt from the withholding tax described above and instead will be subject to U.S. federal income tax on a net income basis at the regular graduated U.S. federal income tax rates in the same manner as if the non-U.S. holder were a United States person, as defined under the Code. In such cases, we will not have to withhold U.S. federal income tax if the non-U.S. holder complies with applicable certification and disclosure requirements. In order to obtain this exemption from withholding tax, a non-U.S. holder must provide us with an IRS Form W-8ECI (or applicable substitute or successor form) properly certifying eligibility for such exemption. Any such effectively connected dividends received by a foreign corporation may be subject to an additional branch profits tax at a rate of 30% or such lower rate as may be specified by an applicable tax treaty.

Gain on Disposition of Common Stock

Any gain realized on the disposition of our common stock by a non-U.S. holder generally will not be subject to U.S. federal income tax unless:

- such gain is effectively connected with the conduct of a trade or business by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, is attributable to a permanent establishment or fixed based in the United States);

the non-U.S. holder is an individual who is present in the United States for 183 days or more in the taxable year of the disposition, and certain other conditions are met; or

we are or have been a United States real property holding corporation, or USRPHC, for U.S. federal income tax purposes.

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An individual non-U.S. holder who has gain that is described in the first bullet point immediately above will be subject to tax on the gain derived from the disposition under regular graduated U.S. federal income tax rates. If a non-U.S. holder that is a foreign corporation has gain described under the first bullet point immediately above, it generally will be subject to tax on its gain in the same manner as if it were a United States person, as defined under the Code, and, in addition, may be subject to the branch profits tax equal to 30% of its effectively connected earnings and profits or at such lower rate as may be specified by an applicable income tax treaty.

An individual non-U.S. holder who meets the requirements described in the second bullet point immediately above will be subject to a flat 30% tax on the gain derived from the disposition, which may be offset by U.S. source capital losses, even though the individual is not considered a resident of the United States.

With respect to our status as a USRPHC, we believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, so long as our common stock is considered to be regularly traded on an established securities market, a non-U.S. holder will be taxable on gain recognized on the disposition of our common stock only if the non-U.S. holder actually or constructively holds or held more than 5% of such common stock at any time during the five-year period ending on the date of disposition or, if shorter, the non-U.S. holder s holding period for our common stock. If our common stock were not considered to be regularly traded on an established securities market, all non-U.S. holders would be subject to U.S. federal income tax on a disposition of our common stock.

Non-U.S. holders should consult their tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our common stock.

Federal Estate Tax

If you are an individual, common stock owned or treated as being owned by you at the time of your death will be included in your gross estate for U.S. federal estate tax purposes and may be subject to U.S. federal estate tax, unless an applicable estate tax treaty provides otherwise.

Information Reporting and Backup Withholding

We must report annually to the IRS and to each non-U.S. holder the amount of dividends paid to such holder and the tax withheld with respect to such dividends, regardless of whether withholding was required. Copies of the information returns reporting such dividends and withholding may also be made available to the tax authorities in the country in which the non-U.S. holder resides under the provisions of an applicable income tax treaty.

A non-U.S. holder will be subject to backup withholding for dividends paid to such holder unless such holder certifies under penalties of perjury that it is a non-U.S. holder (and the payor does not have actual knowledge or reason to know that such holder is a United States person, as defined under the Code), or such holder otherwise establishes an exemption.

Information reporting and, depending on the circumstances, backup withholding (at the applicable rate) will apply to the proceeds of a sale of our common stock within the United States or conducted through certain U.S. related financial intermediaries, unless the beneficial owner certifies under penalties of perjury that it is a non-U.S. holder (and the payor does not have actual knowledge or reason to know that the beneficial owner is a United States person, as defined under the Code), or such owner otherwise establishes an exemption.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules may be allowed as a refund or a credit against a non-U.S. holder s U.S. federal income tax liability provided the required information is furnished to the IRS.

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UNDERWRITING

Barclays Capital Inc. is acting as the representative of the underwriters and the sole book-running manager of this offering. Under the terms of an underwriting agreement, which we will file as an exhibit to our current report on Form 8-K and incorporate by reference in this prospectus, each of the underwriters named below has severally agreed to purchase from us the respective number of common stock shown opposite its name below:

Underwriters	Number of Shares
Barclays Capital Inc.	
Total	

The underwriting agreement provides that the underwriters obligation to purchase shares of common stock depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the shares of common stock offered hereby (other than those shares of common stock covered by their option to purchase additional shares as described below), if any of the shares are purchased;
- the representations and warranties made by us to the underwriters are true;
- there is no material change in our business or in the financial markets; and
- we deliver customary closing documents to the underwriters

Commissions and Expenses

The following table summarizes the underwriting discounts and commissions we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional shares. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us for the shares.

	No Exercise	Full Exercise
Per Share		
Total		

The representative of the underwriters has advised us that the underwriters propose to offer the shares of common stock directly to the public at the public offering price on the cover of this prospectus and to selected dealers, which may include the underwriters, at such offering price less a selling concession not in excess of $ per share. After the offering, the representative may change the offering price and other selling terms. Sales of shares made outside of the United States may be made by affiliates of the underwriters.

The expenses of the offering that are payable by us are estimated to be $ (excluding underwriting discounts and commissions).

Option to Purchase Additional Shares

We have granted the underwriters an option exercisable for 30 days after the date of this prospectus, to purchase, from time to time, in whole or in part, up to an aggregate of shares at the public offering price less underwriting discounts and commissions. This option may be exercised if the underwriters sell more than shares in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional shares based on the underwriter s percentage underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting Section.

Lock-Up Agreements

We, all of our directors and executive officers and Oaktree Holdings have agreed that, subject to certain exceptions, without the prior written consent of Barclays Capital Inc., we and they will not directly or indirectly (1) offer for sale, sell, pledge, or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any shares of common stock (including, without limitation, shares of common stock that may be deemed to be beneficially owned by us or them in accordance with the rules and regulations of the Securities and Exchange Commission and shares of common stock that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for common stock, (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock, (3) make any demand for or exercise any right or file or cause to be filed a registration statement, including any amendments thereto, with respect to the registration of any shares of common stock or securities convertible, exercisable or exchangeable into common stock or any of our other securities, or (4) publicly disclose the intention to do any of the foregoing for a period of 180 days after the date of this prospectus except (a) the issuance of common stock pursuant to the exercise by directors or officers (or their estates or other permitted successors in interest) of stock options or other equity awards outstanding on the date hereof, (b) grants of stock options, restricted stock or other equity awards pursuant to the terms of a plan in effect on the date hereof covering directors and employees, (c) transfers to family members or a trust, so long as such parties agree to be locked-up for the remainder of the lock-up period, (d) the withholding or repurchase by the company of shares of common stock for the purpose of satisfying tax liabilities associated with the vesting or exercise of awards granted pursuant to an equity plan of the company existing as of the date hereof and (e) private issuances of securities in connection with acquisitions (provided the recipients of such securities agree to be subject to similar restrictions).

The 180-day restricted period described in the preceding paragraph will be extended if:

- during the last 17 days of the 180-day restricted period we issue an earnings release or material news or a material event relating to us occurs; or

- prior to the expiration of the 180-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 180-day period;

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or material event, unless such extension is waived in writing by Barclays Capital.

Barclays Capital Inc., in its sole discretion, may release the common stock and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common stock and other securities from lock-up agreements, Barclays Capital Inc. will consider, among other factors, the holder s reasons for requesting the release, the number of shares of common stock and other securities for which the release is being requested and market conditions at the time.

Indemnification

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities.

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Stabilization, Short Positions and Penalty Bids

The representative may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing or maintaining the price of the common stock, in accordance with Regulation M under the Securities Exchange Act of 1934:

Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

A short position involves a sale by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of shares involved in the sales made by the underwriters in excess of the number of shares they are obligated to purchase is not greater than the number of shares that they may purchase by exercising their option to purchase additional shares. In a naked short position, the number of shares involved is greater than the number of shares in their option to purchase additional shares. The underwriters may close out any short position by either exercising their option to purchase additional shares and/or purchasing shares in the open market. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through their option to purchase additional shares. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions.

Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of the common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on Nasdaq or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters make representation that the representative will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the Internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of shares for sale to online brokerage account holders. Any such allocation for online distributions will be made by the representative on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter s or selling group member s web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

The NASDAQ Global Market

We have applied to list our shares of common stock on the NASDAQ Global Market under the symbol CXPO.

Discretionary Sales

The underwriters have informed us that they do not intend to confirm sales to discretionary accounts that exceed 5% of the total number of shares offered by them.

Stamp Taxes

If you purchase shares of common stock offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

Relationships/FINRA Rules

Certain of the underwriters and their related entities have engaged, and may in the future engage, in investment banking transactions with us in the ordinary course of their business. They have received, and expect to receive, customary compensation and expense reimbursement for these investment banking transactions.

Selling Restrictions

United Kingdom

This prospectus is only being distributed to, and is only directed at, persons in the United Kingdom that are qualified investors within the meaning of Article 2(1)(e) of the Prospectus Directive (Qualified Investors) that are also (i) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the Order) or (ii) high net worth entities, and other persons to whom it may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as relevant persons). This prospectus and its contents are confidential and should not be distributed, published or reproduced (in whole or in part) or disclosed by recipients to any other persons in the United Kingdom. Any person in the United Kingdom that is not a relevant persons should not act or rely on this document or any of its contents.

European Economic Area

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of securities described in this prospectus may not be made to the public in that relevant member state other than:

to any legal entity that is authorized or regulated to operate in the financial markets or, if not so authorized or regulated, whose corporate purpose is solely to invest in securities;

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to any legal entity that has two or more of (1) an average of at least 250 employees during the last financial year; (2) a total balance sheet of more than 43,000,000 and (3) an annual net turnover of more than 50,000,000, as shown in its last annual or consolidated accounts;

to fewer than 100 natural or legal persons (other than qualified investors as defined in the Prospectus Directive) subject to obtaining the prior consent of the representative; or

in any other circumstances that do not require the publication of a prospectus pursuant to Article 3 of the Prospectus Directive,

provided that no such offer of securities shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an offer of securities to the public in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe the securities, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression Prospectus Directive means Directive 2003/71/EC and includes any relevant implementing measure in each relevant member state.

We have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the underwriters, is authorized to make any further offer of the securities on behalf of us or the underwriters.

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WHERE YOU CAN FIND MORE INFORMATION

Crimson Exploration has historically filed annual, quarterly and current reports, proxy statements and other information with the SEC. We will continue to fulfill our obligations with respect to such requirements by filing periodic reports, proxy statements and other information with the SEC. We intend to furnish our stockholders with annual reports containing consolidated financial statements certified by an independent public accounting firm.

You may read and copy any document we have or will file with the SEC at the SEC s public website (http://www.sec.gov) or at the Public Reference Room of the SEC located at 100 F Street, N.E., Washington, D.C. 20549. Copies of such materials, including copies of all or any portion of the registration statement, can be obtained from the Public Reference Room of the SEC at prescribed rates. You can call the SEC at 1-800-SEC-0330 to obtain information on the operation of the Public Reference Room.

We have filed with the SEC a registration statement on Form S-1 under the Securities Act relating to this offering. This prospectus, which is part of the registration statement, does not contain all of the information provided in the registration statement and the exhibits to the registration statement. For further information with respect to us and this offering, you should refer to the registration statement and the exhibits filed as a part of the registration statement. If we have made references in this prospectus to any contracts, agreements or other documents and also filed any of those contracts, agreements or other documents as exhibits to the registration statement, you should read the relevant exhibit for a more complete understanding of the document or the matter involved.

The SEC allows us to incorporate by reference the information we file with it, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this prospectus, unless that information is updated and superseded by the information in this document. We incorporate by reference (other than any information furnished under Item 2.02 or 7.01 on a Current Report on Form 8-K) the documents listed below:

Our Annual Report on Form 10-K for the year ended December 31, 2008, filed March 27, 2009

Our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed May 15, 2009

Our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, filed August 12, 2009

Our Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed November 16, 2009

Our Current Report on Form 8-K filed November 13, 2009

Our Current Report on Form 8-K filed November 16, 2009

Our Current Report on Form 8-K filed August 14, 2009

Our Current Report on Form 8-K filed August 5, 2009

Our Current Report on Form 8-K filed May 19, 2009

Our Current Report on Form 8-K filed April 1, 2009

Our Current Report on Form 8-K filed February 27, 2009

Our Current Report on Form 8-K filed January 5, 2009

Our Definitive Proxy Statement on Schedule 14A filed April 24, 2009

You may obtain copies of this information, including the documents referenced in this prospectus or any filing incorporated by reference herein and filed as exhibits to the registration statement of which this prospectus is a part or any filing incorporated by reference herein, at no charge by writing or telephoning us at the following address and telephone number:

Crimson Exploration Inc.
Attention: Investor Relations
717 Texas Avenue, Suite 2900
Houston, Texas 77002
713-236-7400

We also maintain an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.crimsonexploration.com. The filings incorporated by reference in this prospectus may be accessed on our website. Other information contained on our website or connected thereto shall not be deemed to be incorporated into this prospectus or the registration statement of which this prospectus forms a part, and you should not rely on any such information in making your decision whether to purchase our securities.

LEGAL MATTERS

Akin Gump Strauss Hauer & Feld LLP will pass upon for us the validity of the shares of our common stock offered hereby. Certain legal matters in connection with the offering will be passed upon for the underwriters by Vinson and Elkins L.L.P.

EXPERTS

The consolidated financial statements and schedules included in this prospectus and elsewhere in the registration statement have been so included in reliance upon the reports of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in giving said reports.

Estimates of our proved crude oil and natural gas reserves included herein were based in part upon an engineering report prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. These estimates are included herein in reliance on the authority of such firm as an expert in such matters.

Appendix A

GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this prospectus.

2D seismic or 3D seismic. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this prospectus in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. Million barrels of crude oil or other liquid hydrocarbons.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

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MMcf/d. Mmcf per day.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

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

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

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

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(4) of Regulation S-X, which defines proved undeveloped reserves as reserves that are expected to be

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

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Trucking. The provision of trucks to move our drilling rigs from one well location to another and to deliver water and equipment to the field.

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

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

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Appendix B

RESERVE REPORT

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February 13, 2009

Mr. Rusty Shepherd Crimson
Exploration Inc. 717 Texas
Avenue, Suite 2900 Houston,
Texas 77002

Dear Mr. Shepherd:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2008, to the Crimson Exploration Inc. (Crimson) interest in certain oil and gas properties located in the United States and in the Gulf of Mexico, as listed in the accompanying tabulations. This report has been prepared using constant prices and costs, as discussed in subsequent paragraphs of this letter. The estimates of reserves and future revenue in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission and, with the exception of the exclusion of future income taxes, conform to the Statement of Financial Accounting Standards No. 69. Definitions are presented immediately following this letter.

As presented in the accompanying summary projections, Tables I through IV, we estimate the net reserves and future net revenue to the Crimson interest in these properties, as of December 31, 2008, to be:

	Net Reserves			**Future Net Revenue ($)**	
Category	**Oil (Barrels)**	**NGL (Barrels)**	**Gas (MCF)**	**Total**	**Present Worth at 10%**
Proved Developed					
Producing	1,164,981	1,629,635	48,457,379	240,575,200	180,036,200
Non-Producing	450,993	793,243	18,254,400	97,027,700	55,676,200
Proved Undeveloped	947,751	976,351	29,456,965	110,481,200	55,237,300
Total Proved	2,563,725	3,399,229	96,168,734	448,084,000	290,949,800

Totals may not add because of rounding.

The oil reserves shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in barrels that are equivalent to 42 United States gallons. Gas volumes are expressed in thousands of cubic feet (MCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved developed producing, proved developed non-producing, and proved undeveloped reserves. Our estimates do not include any probable or possible reserves that may exist for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk. As shown in the Table of Contents, for each reserves category this report includes a summary projection of reserves and revenue along with one-line summaries of basic data, reserves, and economics by lease.

Future gross revenue to the Crimson interest is prior to deducting state production taxes and ad valorem taxes. Future net revenue is after deductions for these taxes, future capital costs, and operating expenses but before consideration of federal income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth. The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and their related facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Also, our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties.

Oil and NGL prices used in this report are based on a December 31, 2008, West Texas Intermediate posted price of $41.00 per barrel and are adjusted by lease for quality, transportation fees, and regional price differentials. Gas prices used in this report are based on a December 31, 2008, Henry Hub spot market price of $5.71 per MMBTU and are adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties.

Lease and well operating costs used in this report are based on operating expense records of Crimson. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Headquarters general and administrative overhead expenses of Crimson are included to the extent that they are covered under joint operating agreements for the operated properties. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the Crimson interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Crimson receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. The reserves may or may not be recovered; if they are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. A substantial portion of these reserves are for behind-pipe zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics; it may be necessary to revise these estimates as additional performance data become available. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report. Also, estimates of reserves may increase or decrease as a result of future operations.

In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geologic. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geologic data; therefore, our conclusions necessarily represent only informed professional judgment.

The titles to the properties have not been examined by Netherland, Sewell & Associates, Inc., nor has the actual degree or type of interest owned been independently confirmed. The data used in

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our estimates were obtained from Crimson, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting geologic, field performance, and work data are on file in our office. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties and are not employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ C.H. (Scott) Rees III, P.E.
By: C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ Richard B. Talley, Jr., P.E.
By: Richard B. Talley, Jr., P.E.
Vice President

Date Signed: February 13, 2009

/s/ David E. Nice, P.G.
By: David E. Nice, P.G.
Vice President

Date Signed: February 13, 2009

RBT:JJH

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates, Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

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DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a)

The following definitions of proved reserves are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included (in italics) are certain subsequent interpretations set forth in the SEC s Corporate Finance Accounting Interpretations and Guidance [SEC Interpretations]; SEC Staff Accounting Bulletins: Topic 12 [SEC Topic 12]; the Statement of Financial Accounting Standards No. 69 [FASB 69]; and the 2007 Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE) [SPE-PRMS].

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

The determination of reasonable certainty is generated by supporting geological and engineering data. There must be data available which indicate that assumptions such as decline rates, recovery factors, reservoir limits, recovery mechanisms and volumetric estimates, gas-oil ratios or liquid yield are valid. If the area in question is new to exploration and there is little supporting data for decline rates, recovery factors, reservoir drive mechanisms etc., a conservative approach is appropriate until there is enough supporting data to justify the use of more liberal parameters for the estimation of proved reserves. The concept of reasonable certainty implies that, as more technical data becomes available, a positive, or upward, revision is much more likely than a negative, or downward, revision.

Existing economic and operating conditions are the product prices, operating costs, production methods, recovery techniques, transportation and marketing arrangements, ownership and/or entitlement terms and regulatory requirements that are extant on the effective date of the estimate. An anticipated change in conditions must have reasonable certainty of occurrence; the corresponding investment and operating expense to make that change must be included in the economic feasibility at the appropriate time. These conditions include estimated net abandonment costs to be incurred and duration of current licenses and permits.

If oil and gas prices are so low that production is actually shut-in because of uneconomic conditions, the reserves attributed to the shut-in properties can no longer be classified as proved and must be subtracted from the proved reserve data base as a negative revision. Those volumes may be included as positive revisions to a subsequent year s proved reserves only upon their return to economic status. [SEC Interpretations]

A standardized measure of discounted future net cash flows relating to an enterprise s interests in (a) proved oil and gas reserves (paragraph 10) and (b) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (paragraph 13) shall be disclosed as of the end of the year. The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes. The following

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a)

information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraph 12:

a. Future cash inflows. These shall be computed by applying year-end prices of oil and gas relating to the enterprise s proved reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the enterprise s proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to permanent differences and tax credits and allowances relating to the enterprise s proved oil and gas reserves.

d. Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount. [FASB 69]

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

Proved reserves may be attributed to a prospective zone if a conclusive formation test has been performed or if there is production from the zone at economic rates. It is clear to the SEC staff that wireline recovery of small volumes (e.g. 100 cc) or production of a few hundred barrels per day in remote locations is not necessarily conclusive. Analyses of open-hole well logs which imply that an interval is productive are not sufficient for attribution of proved reserves. If there is an indication of economic producibility by either formation test or production, the reserves in the legal and technically justified drainage area around the well projected down to a known fluid contact or the lowest known hydrocarbons, or LKH may be considered to be proved.

In order to attribute proved reserves to legal locations adjacent to such a well (i.e. offsets), there must be conclusive, unambiguous technical data which supports reasonable certainty of production of such volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the LKH. In the absence

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a)

of a fluid contact, no offsetting reservoir volume below the LKH from a well penetration shall be classified as proved.

Upon obtaining performance history sufficient to reasonably conclude that more reserves will be recovered than those estimated volumetrically down to LKH, positive reserve revisions should be made. [SEC Interpretations]

Economic producibility of estimated proved reserves can be supported to the satisfaction of the Office of Engineering if geological and engineering data demonstrate with reasonable certainty that those reserves can be recovered in future years under existing economic and operating conditions. The relative importance of the many pieces of geological and engineering data which should be evaluated when classifying reserves cannot be identified in advance. In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. [SEC Topic 12]

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

If an improved recovery technique which has not been verified by routine commercial use in the area is to be applied, the hydrocarbon volumes estimated to be recoverable cannot be classified as proved reserves unless the technique has been demonstrated to be technically and economically successful by a pilot project or installed program in that specific rock volume. Such demonstration should validate the feasibility study leading to the project. [SEC Interpretations]

Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Geologic and reservoir characteristic uncertainties such as those relating to permeability, reservoir continuity, sealing nature of faults, structure and other unknown characteristics may prevent reserves from being classified as proved. Economic uncertainties such as the lack of a market (e.g. stranded hydrocarbons), uneconomic prices and marginal reserves that do not show a positive cash flow can also prevent reserves from being classified as proved. Hydrocarbons manufactured through extensive treatment of gilsonite, coal and oil shales are mining activities reportable under Industry Guide 7. They cannot be called proved oil

DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a)

and gas reserves. However, coal bed methane gas can be classified as proved reserves if the recovery of such is shown to be economically feasible.

In developing frontier areas, the existence of wells with a formation test or limited production may not be enough to classify those estimated hydrocarbon volumes as proved reserves. Issuers must demonstrate that there is reasonable certainty that a market exists for the hydrocarbons and that an economic method of extracting, treating and transporting them to market exists or is feasible and is likely to exist in the near future. A commitment by the company to develop the necessary production, treatment and transportation infrastructure is essential to the attribution of proved undeveloped reserves. Significant lack of progress on the development of such reserves may be evidence of a lack of such commitment. Affirmation of this commitment may take the form of signed sales contracts for the products; request for proposals to build facilities; signed acceptance of bid proposals; memos of understanding between the appropriate organizations and governments; firm plans and timetables established; approved authorization for expenditures to build facilities; approved loan documents to finance the required infrastructure; initiation of construction of facilities; approved environmental permits etc. Reasonable certainty of procurement of project financing by the company is a requirement for the attribution of proved reserves. An inordinately long delay in the schedule of development may introduce doubt sufficient to preclude the attribution of proved reserves.

The history of issuance and continued recognition of permits, concessions and commerciality agreements by regulatory bodies and governments should be considered when determining whether hydrocarbon accumulations can be classified as proved reserves. Automatic renewal of such agreements cannot be expected if the regulatory body has the authority to end the agreement unless there is a long and clear track record which supports the conclusion that such approvals and renewal are a matter of course. [SEC Interpretations]

Companies should report reserves of natural gas liquids which are net to their leasehold interests, i.e., that portion recovered in a processing plant and allocated to the leasehold interest. It may be appropriate in the case of natural gas liquids not clearly attributable to leasehold interests ownership to follow instructions to Item 3 of Securities Act Industry Guide 2 and report such reserves separately and describe the nature of the ownership. [SEC Topic 12]

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

Currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or bore hole stimulation treatment would be examples of properties with proved developed reserves since the majority of the expenditures to develop the reserves has already been spent.

Proved developed reserves from improved recovery techniques can be assigned after either the operation of an installed pilot program shows a positive production response to the

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DEFINITIONS OF OIL AND GAS RESERVES
Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a)

technique or the project is fully installed and operational and has shown the production response anticipated by earlier feasibility studies. In the case with a pilot, proved developed reserves can be assigned only to that volume attributable to the pilot s influence. In the case of the fully installed project, response must be seen from the full project before all the proved developed reserves estimated can be assigned. If a project is not following original forecasts, proved developed reserves can only be assigned to the extent actually supported by the current performance. An important point here is that attribution of incremental proved developed reserves from the application of improved recovery techniques requires the installation of facilities and a production increase. [SEC Interpretations]

Developed Producing Reserves. Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves. Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. [SPE-PRMS]

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

The SEC staff points out that this definition contains no mitigating modifier for the word certainty. Also, continuity of production requires more than the technical indication of favorable structure alone (e.g. seismic data) to meet the test for proved undeveloped reserves. Generally, proved undeveloped reserves can be claimed only for legal and technically justified drainage areas offsetting an existing productive well (but structurally no lower than LKH). If there are at least two wells in the same reservoir which are separated by more than one legal location and which show communication (reservoir continuity), proved undeveloped reserves could be claimed between the two wells, even though the location in question might be more than an offset well location away from any of the wells. In this illustration, seismic data could be used to help support this claim by showing reservoir continuity between the wells, but the required data would be the conclusive evidence of communication from production or pressure tests. The SEC staff emphasizes that proved reserves cannot be claimed more than one offset location away from a productive well if there are no other wells in the reservoir, even though seismic data may exist. The use of high-quality, well calibrated seismic data can improve reservoir description for performing volumetrics (e.g. fluid contacts). However, seismic data is

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Rule 4-10(a)

not an indicator of continuity of production and, therefore, can not be the sole indicator of additional proved reserves beyond the legal and technically justified drainage areas of wells that were drilled. Continuity of production would have to be demonstrated by something other than seismic data.

In a new reservoir with only a few wells, reservoir simulation or application of generalized hydrocarbon recovery correlations would not be considered a reliable method to show increased proved undeveloped reserves. With only a few wells as data points from which to build a geologic model and little performance history to validate the results with an acceptable history match, the results of a simulation or material balance model would be speculative in nature. The results of such a simulation or material balance model would not be considered to be reasonably certain to occur in the field to the extent that additional proved undeveloped reserves could be recognized. The application of recovery correlations which are not specific to the field under consideration is not reliable enough to be the sole source for proved reserve calculations.

Reserves cannot be classified as proved undeveloped reserves based on improved recovery techniques until such time that they have been proved effective in that reservoir or an analogous reservoir in the same geologic formation in the immediate area. An analogous reservoir is one having at least the same values or better for porosity, permeability, permeability distribution, thickness, continuity and hydrocarbon saturations.

(g) Topic 12 of Accounting Series Release No. 257 of the Staff Accounting Bulletins states:

In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.

If the combination of data from open-hole logs and core analyses is overwhelmingly in support of economic producibility and the indicated reservoir properties are analogous to similar reservoirs in the same field that have produced or demonstrated the ability to produce on a conclusive formation test, the reserves may be classified as proved. This would probably be a rare event especially in an exploratory situation. The essence of the SEC definition is that in most cases there must at least be a conclusive formation test in a new reservoir before any reserves can be considered to be proved. [SEC Interpretations]

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Crimson Exploration Inc.

We have audited the accompanying consolidated balance sheets of Crimson Exploration Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

/s/ GRANT THORNTON LLP

Houston, Texas
March 26, 2009

CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$	$ 4,882,511
Accounts receivable, net of allowance	21,078,815	30,034,558
Prepaid expenses	77,293	230,870
Derivative instruments	25,191,445	198,708
Deferred tax asset, net		1,134,918
Total current assets	46,347,553	36,481,565
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	584,093,885	407,905,609
Other property and equipment	3,282,088	2,710,995
Accumulated depreciation, depletion and amortization	(138,220,237)	(54,128,002)
Total property and equipment, net	449,155,736	356,488,602
NONCURRENT ASSETS		
Deposits	104,697	94,591
Debt issuance cost, net	2,890,094	3,982,023
Deferred charges	1,324,907	1,400,000
Derivative instruments	11,722,802	
Deferred tax asset, net		488,293
Total noncurrent assets	16,042,500	5,964,907
TOTAL ASSETS	$ 511,545,789	$ 398,935,074
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Current portion of long-term debt	$ 90,368	$ 100,609
Accounts payable trade	47,726,858	41,432,777
Income tax payable	546,944	
Accrued liabilities	24,369,060	3,234,553
Asset retirement obligations	1,659,371	1,407,347
Derivative instruments	1,265,801	2,703,959
Deferred tax liability, net	8,331,208	

Total current liabilities	83,989,610	48,879,245
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	276,690,426	260,064,226
Asset retirement obligations	11,409,171	6,148,144
Derivative instruments	1,491,755	12,747,019
Deferred tax liability, net	15,609,315	
Other noncurrent liabilities	732,709	1,443,359
Total noncurrent liabilities	305,933,376	280,402,748
Total liabilities	389,922,986	329,281,993
COMMITMENTS AND CONTINGENCIES (see Note 11)		
STOCKHOLDERS EQUITY		
Preferred stock (see Note 12)	826	832
Common stock (see Note 12)	5,808	5,128
Additional paid-in capital	95,676,875	89,507,073
Retained earnings (deficit)	26,189,888	(19,859,952)
Treasury stock (see Note 12)	(250,594)	
Total stockholders equity	121,622,803	69,653,081
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 511,545,789	$ 398,935,074

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2008	2007	2006
OPERATING REVENUES			
Natural gas sales	$ 116,414,956	$ 67,867,605	$ 10,569,705
Crude oil sales	41,860,385	27,021,296	10,908,030
Natural gas liquids sales	27,404,774	14,272,712	
Operating overhead and other income	1,088,158	381,595	181,746
Total operating revenues	186,768,273	109,543,208	21,659,481
OPERATING EXPENSES			
Lease operating expenses	20,824,629	12,033,963	5,633,069
Production and ad valorem taxes	16,266,493	11,701,908	1,894,520
Exploration expenses	9,965,372	3,174,415	673,015
Depreciation, depletion and amortization	50,466,966	30,796,487	4,035,452
Impaired assets of oil and gas properties	35,953,586	4,362,186	3,149,980
General and administrative	22,405,639	14,541,780	8,729,674
(Gain) loss on sale of assets	(15,209,706)	(683,830)	2,456
Total operating expenses	140,672,979	75,926,909	24,118,166
INCOME (LOSS) FROM OPERATIONS	46,095,294	33,616,299	(2,458,685)
OTHER INCOME (EXPENSE)			
Interest expense, net of amount capitalized	(21,108,603)	(14,949,358)	(108,961)
Other financing costs	(1,501,627)	(1,321,661)	(228,320)
Loss from equity in investments			(1,843)
Unrealized gain (loss) on derivative instruments	49,408,961	(18,186,158)	6,082,058
Total other income (expense)	26,798,731	(34,457,177)	5,742,934
INCOME (LOSS) BEFORE INCOME TAXES	72,894,025	(840,878)	3,284,249
Income Tax (Expense) Benefit	(26,690,807)	410,361	(1,425,305)
NET INCOME (LOSS)	46,203,218	(430,517)	1,858,944
Dividends on Preferred Stock (Paid 2008-$153,378; 2007-$702,948; 2006-$154,875)	(4,234,050)	(4,453,872)	(3,648,925)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ 41,969,168	$ (4,884,389)	$ (1,789,981)

NET INCOME (LOSS) PER SHARE			
Basic	$ 7.81	$ (1.13)	$ (0.55)
Diluted	$ 4.46	$ (1.13)	$ (0.55)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	5,371,377	4,330,282	3,231,000
Diluted	10,360,348	4,330,282	3,231,000

The Notes to Consolidated Financial Statements are an integral part of these statements.

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY FOR THE YEARS ENDED DECEMBER 31, 2008, 2007 and 2006

	Number of Shares Preferred Stock	Number of Shares Common Stock	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings (Deficit)	Treasury Stock	Tota Stockhol Equit
NCE, DECEMBER 05	103,250	2,899,182	$ 1,033	$ 2,899	$ 72,877,718	$ (20,076,388)	$	$ 52,80
based compensation		28,644		29	3,876,985			3,87
ptions exercised		10,700		11	48,139			4
ed H converted	(30)	4,287	(1)	4	(3)			
ition of oil and gas		369,789		370	2,736,043			2,73
t year net income						1,858,944		1,85
nds paid on ed stock		21,000		21	154,854	(154,875)		
NCE, DECEMBER 06	103,220	3,333,602	1,032	3,334	79,693,736	(18,372,319)		61,32
ative effect of ng FIN 48						(354,168)		(35
based compensation		252,818		253	4,531,930			4,53
ptions and warrants ed		4,000		5	4,795			4
ed H converted	(3,020)	431,430	(30)	430	(400)			
ed E converted	(9,000)	225,000	(90)	225	(135)			
ed D converted	(8,000)	50,000	(80)	50	30			
ition of oil and gas		750,000		750	4,574,250			4,57
t year net loss						(430,517)		(43
nds paid on ed stock		81,087		81	702,867	(702,948)		
NCE, DECEMBER 07	83,200	5,127,937	832	5,128	89,507,073	(19,859,952)		69,65
based compensation		547,168		547	5,670,051			5,67
ptions exercised		75,000		75	346,425			34
ed G converted	(500)	27,778	(5)	28	(23)			
ed H converted	(100)	14,286	(1)	14	(13)			
t year net income						46,203,218		46,20
nds paid on ed stock		15,743		16	153,362	(153,378)		
ry stock		(20,625)					(250,594)	(25

NCE, DECEMBER 08	82,600	5,787,287	$	826	$	5,808	$	95,676,875	$	26,189,888	$	(250,594)	$	121,62

The Notes to Consolidated Financial Statements are an integral part of these statements.

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31, 2008	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 46,203,218	$ (430,517)	$ 1,858,944
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	50,466,966	30,796,487	4,035,452
Asset retirement obligations	(546,840)	(268,445)	(14,113)
Stock compensation expense	5,434,992	4,738,125	3,819,600
Debt issuance cost	1,091,929	1,059,033	134,131
Deferred charges	75,093	(1,400,000)	
Income taxes (current and deferred)	26,110,678	(410,361)	1,425,305
Dry holes, abandoned property, impaired assets	43,309,365	5,710,125	3,209,943
(Gain) loss on sale of assets	(15,209,706)	(683,830)	2,456
Loss from equity in investments			1,843
Unrealized (gain) loss on derivative instruments	(49,408,961)	18,186,158	(6,082,058)
Provision for bad debts		96,904	87,436
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable trade, net	8,973,958	(22,648,152)	(161,811)
(Increase) decrease in prepaid expenses	153,577	(5,566)	24,120
Increase in accounts payable and accrued liabilities	27,114,462	34,871,687	5,946,284
Net cash provided by operating activities	143,768,731	69,611,648	14,287,532
CASH FLOWS FROM INVESTING ACTIVITIES:			
Proceeds from sale of assets	34,923,332	756,650	7,950
Acquisition of oil and gas properties	(58,481,721)	(253,434,220)	
Capital expenditures	(141,794,612)	(59,048,764)	(21,777,332)
Deposits	(10,106)	(45,089)	
Net cash used in investing activities	(165,363,107)	(311,771,423)	(21,769,382)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from exercise of common stock options and warrants	346,500	4,800	48,150
Purchase of treasury stock	(250,594)		
Payments on debt	(132,393,063)	(68,571,595)	(18,805,206)
Proceeds from debt	149,009,022	320,177,233	26,097,334
Debt issuance expenditures		(4,591,473)	(309,500)
Net cash provided by financing activities	16,711,865	247,018,965	7,030,778
	(4,882,511)	4,859,190	(451,072)

INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS						
CASH AND CASH EQUIVALENTS, Beginning of year		4,882,511		23,321		474,393
CASH AND CASH EQUIVALENTS, End of year	$		$	4,882,511	$	23,321
Cash Paid For Interest	$	22,484,711	$	14,914,194	$	291,163
Cash Paid For Income Taxes	$	580,129	$		$	31,000
Non-Cash Stock Issuance For Oil And Gas Properties	$		$	4,575,000	$	2,736,413

The Notes to Consolidated Financial Statements are an integral part of these statements.

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization

Crimson Exploration Inc., together with its subsidiaries, (*Crimson* , *we* , *our* , *us*) is an independent energy company engaged in the acquisition, development, exploitation and production of crude oil, natural gas and natural gas liquids, principally in the onshore gulf coast regions of Texas and Louisiana and in Colorado.

Organization

In June 2005, our predecessor, GulfWest Energy Inc., a Texas corporation (*GulfWest*), merged with and into Crimson Exploration Inc., a Delaware corporation (*Crimson*), for the purpose of changing our state of incorporation from Texas to Delaware (*Reincorporation*). The Reincorporation was accomplished pursuant to an Agreement and Plan of Merger, dated June 28, 2005, which was approved by GulfWest s stockholders at the 2005 Annual Stockholders Meeting held June 1, 2005.

In January 2006, we formed Crimson Exploration Operating, Inc. (*CEO*), a Delaware corporation, as our wholly owned subsidiary through which all operations are conducted. Effective March 2, 2006, we merged all our subsidiaries, with the exception of LTW Pipeline Co., into this newly formed corporation. LTW Pipeline Co. remains an inactive subsidiary of Crimson Exploration Inc.

In September 2006, we effected a reverse stock split where each ten shares of outstanding common stock were exchanged for one new share of common stock. All periods presented have been adjusted to reflect the effects of the reverse stock split.

On May 8, 2007, CEO acquired certain natural gas and crude oil properties and related assets in the South Texas and Gulf Coast areas of Louisiana and Texas (*STGC Properties*) pursuant to a Membership Interest Purchase and Sale Agreement (*Purchase Agreement*) from EXCO Resources, Inc. (*EXCO*) through the acquisition of 100% of the membership interest of Southern G Holdings, LLC (*SGH*). These properties were operated under SGH until SGH merged with CEO on December 31, 2007. The consolidated statements of operations include the results of operations of the STGC Properties from May to present.

Segments

Our operations are considered to fall within a single industry segment, which is the acquisition, development, exploitation and production of natural gas and crude oil properties in the United States.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation, including a breakout of sales by commodity, a breakout of production and ad valorem taxes from lease operating expenses and a reclassification of asset retirement obligations. We reclassified accretion expense from asset retirement obligations to depreciation, depletion and amortization. We also reclassified net settled asset retirement obligations expense from asset retirement obligations to exploration expenses. All of these reclassifications were made based on the materiality of these items to the Consolidated Statements of Operations. These changes had no impact on Total Operating Revenues, Income (Loss) from Operations or Net Income (Loss) as previously disclosed.

2. Summary of Significant Accounting Policies

Cash and Cash Equivalents

We consider all highly liquid investment instruments purchased with remaining maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows and other statements. We maintain cash on deposit in non-interest bearing accounts, which, at times, exceed federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Use of Estimates in the Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Gas Properties

We use the successful efforts method of accounting for natural gas and crude oil producing activities. Costs to acquire mineral interests in natural gas and crude oil properties are capitalized. Costs to drill and develop development wells and costs to drill and develop exploratory wells that find proved reserves are also capitalized. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

Capitalized costs of producing natural gas and crude oil properties and support equipment, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depleted by the unit-of-production method.

On the sale of an entire interest in an unproved property, the gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property has been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, the gain or loss is recognized, based upon the fair values of the interests sold and retained.

Oil and Gas Reserves

The estimates of proved natural gas, crude oil and natural gas liquids reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the Securities and Exchange Commission (*SEC*) and the Financial Accounting Standards Board (*FASB*), which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to deplete capitalized natural gas, crude oil and natural gas liquids costs on the unit of production method, based upon these reserve estimates. It is possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of natural gas, crude oil and natural gas liquids reserves, the remaining estimated lives of the natural gas and crude oil properties, or any combination of the above may be increased or reduced. See Note 17 Oil and Gas Reserves (unaudited) for further information.

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Capitalized Interest

Interest is capitalized as part of the historical cost of acquiring assets. Natural gas and crude oil investments in exploration and development activities which are in progress qualify for interest capitalization. Capitalized interest is calculated by multiplying the Company s weighted-average interest rate on debt by the amount of qualifying costs. Capitalized interest cannot exceed gross interest expense. Any associated capitalized interest is transferred to the appropriate asset and is depleted by the unit of production method. Capitalized interest totaled $0.9 million, $1.3 million and $0.2 million in 2008, 2007 and 2006 respectively.

Asset Retirement Obligations

In 2003, we adopted the Statement of Financial Accounting Standards (*SFAS*) No. 143, Asset Retirement Obligations (*SFAS 143*) which requires us to recognize an estimated liability for the plugging and abandonment of our natural gas and crude oil wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which the related assets are placed in service or acquired. The liability is accreted to its present value each period and the capitalized cost is depleted over the useful life of the related asset. The accretion expense is included in depreciation, depletion and amortization (*DD&A*) expense.

The estimated liability is based on historical experience in plugging and abandoning wells. The estimated remaining lives of the wells is based on reserve life estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate or changes in the remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs. This gain or loss on abandonment is included in exploration expenses.

Other Property and Equipment

The following tables set forth certain information with respect to our other property and equipment. With the exception of leasehold improvements, which is amortized over the term of the lease, other property and equipment is recorded at cost, and we provide for depreciation and amortization using the straight-line method over the following estimated useful lives of the respective assets:

Assets	**Years**
Automobiles	3-5
Office equipment	7
Computer software	7
Gathering system	10
Well servicing equipment	10

Capitalized costs relating to other properties and equipment are as follows:

	2008	2007
Automobiles	$ 359,466	$ 407,894
Office equipment	971,173	604,670
Computer software	880,713	742,019
Leasehold improvements	695,688	581,364
Gathering system	271,651	271,651
Well servicing equipment	103,397	103,397
	3,282,088	2,710,995
Less accumulated depreciation	(1,246,427)	(913,157)
Net capitalized cost	$ 2,035,661	$ 1,797,838

Impairments

We have adopted SFAS 144 Accounting for the Impairment or Disposal of Long- Lived Assets. Accordingly, impairments, measured using fair market value, are recognized whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable and the future undiscounted cash flows attributable to the asset are less than its carrying value.

Revenue Recognition and Oil and Gas Imbalances

The Company follows the sales (takes or cash) method of accounting for natural gas, crude oil and natural gas liquids revenues. Under this method, we recognize revenues on production as it is taken and delivered to its purchasers. The volumes sold may be more or less than the volumes we are entitled to based on our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. Our crude oil and natural gas imbalances are not significant.

Trade Accounts Receivable

We grant credit to creditworthy independent and major natural gas and crude oil marketing companies for the sale of natural gas, crude oil and natural gas liquids. In addition, we grant credit to our oil and gas working interest partners. Receivables from our working interest partners are generally secured by the underlying ownership interests in the properties.

The accounts receivable (*A/R*) balance at year-end primarily relates to A/R Trade (net of allowance for doubtful accounts), A/R joint interest billing (net of legal suspense/prepayments from partners), Accrued revenue (one month for operated properties, two months for non-operated properties), and A/R Other. Accrued revenue is recorded net to our interest (excludes outside interest holders).

The allowance for doubtful accounts is recognized by management based upon a review of specific customer balances, historical losses and general economic conditions. The allowance for doubtful accounts at December 31, 2008 and 2007 was $215,015.

Fair Value Measurements

We adopted SFAS No. 157, Fair Value Measurements (*SFAS 157*), as of January 1, 2008 as related to our financial assets and liabilities. SFAS 157 establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Under the standard, additional disclosures are required, including disclosures of fair value measurements by

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level within the fair value hierarchy. As a result of adoption, we began incorporating a credit risk assumption into the measurement of certain assets and liabilities. Adoption of SFAS 157 did not have a significant impact on our consolidated financial statements. See Note 5 Fair Values of Financial Instruments for further information.

We also adopted SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (*SFAS 159*) as of January 1, 2008. SFAS No. 159 provides companies with an option to report selected financial assets and liabilities at fair value. Adoption had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt.

Earnings (Loss) Per Share

We have adopted Statement of Financial Accounting Standards No. 128 Earnings Per Share (*SFAS 128*), which requires that both basic earnings (loss) per share and diluted earnings (loss) per share be presented on the face of the statement of operations. Basic earnings (loss) per share are based on the weighted-average number of outstanding common shares. Diluted earnings (loss) per-share is based on the weighted-average number of outstanding common shares and the effect of all potentially diluted common shares. See Note 14 Income (Loss) Per Common Share for further information.

Share-Based Compensation

We adopted SFAS No. 123R Share-Based Payment (*SFAS 123(R)*) as of January 1, 2006. SFAS 123(R) revised SFAS 123, Accounting for Stock-Based Compensation and nullified Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees and its related implementation guidance. SFAS 123(R) requires companies to measure the grant date fair value of stock options and other stock-based compensation issued to employees and expense the fair value over the requisite service period of the award. It is our policy to issue new shares for any options exercised. We use the Black-Scholes option pricing model to measure the fair value of stock options.

In accordance with SFAS 123(R) we estimate forfeitures in calculating the expense related to stock-based compensation as opposed to recognizing forfeitures as they occur. All of our unvested options are held by our executive officers and new employees. See Note 13 Share-Based Compensation for further information.

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions.

Recent Accounting Pronouncements

SEC 33-8995/34-59192. In December 2008, the SEC adopted Release No. 33-8995/34-59192, Modernization of Oil and Gas Reporting (*SEC 33-8995*). This release amends the oil and gas reporting disclosures that exist in their current form in Regulation S-K and Regulation S-X under the

Securities Act of 1933 and the Securities Exchange Act of 1934 to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The new rules include changes for pricing used to estimate reserves; permitting disclosure of possible and probable reserves; ability to include non-traditional resources in reserves and the use of new technology for determining reserves. SEC 33-8995 is effective for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently evaluating the provisions of SEC 33-8995 and assessing the impact it may have on our financial reporting disclosures.

SFAS 161. In March 2008, the FASB issued SFAS No. 161, Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (*SFAS 161*). SFAS 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations; and (iii) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We are currently evaluating the provisions of SFAS 161 and assessing the impact it may have on our financial reporting disclosures.

SFAS 141(R). In December 2007, the FASB issued a revision to SFAS 141 Business Combinations (*SFAS 141(R)*). The revision broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, the statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. SFAS 141(R) is effective for business combination transactions for which the acquisition date is on or after the beginning of the first reporting period beginning on or after December 15, 2008. Early adoption is prohibited. We are currently evaluating the provisions of SFAS 141(R) and assessing the impact it may have on our financial statements when an applicable acquisition is consummated.

SFAS 157-2. In September 2006, the FASB issued SFAS 157. In February 2008, FASB issued Staff Position (*FSP*) No. SFAS 157-2, Effective Date of FASB Statement No. 157 (*FSP 157-2*). FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). An entity that has issued interim or annual financial statements reflecting the application of the measurement and disclosure provisions of SFAS 157 prior to February 12, 2008, must continue to apply all provisions of SFAS 157. We are currently evaluating the provisions of FSP 157-2 and assessing the impact it may have on our financial position, results of operations and reporting disclosures.

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3. Oil and Gas Properties

The following tables set forth certain information with respect to our oil and gas producing activities (all within the United States) for the periods presented:

Capitalized Costs Relating to Oil and Gas Producing Activities:

	2008	2007
Unproved oil and gas properties	$ 68,278,373	$ 35,059,298
Proved oil and gas properties	489,069,881	361,582,956
Wells and related equipment and facilities	26,745,631	11,263,355
	584,093,885	407,905,609
Less accumulated depreciation, depletion and amortization	(136,973,810)	(53,214,845)
Net capitalized costs	$ 447,120,075	$ 354,690,764

The following table sets forth the composition of exploration expenses:

	2008	2007	2006
Dry holes	$	$ 605,561(1)	$
Lease rental expense	172,384	242,103	220,110
Geological and geophysical	1,692,102	1,430,046	223,386
Settled asset retirement obligations	745,107	69,325	161,520
Abandoned property	7,355,779(2)	827,380	67,999
	$ 9,965,372	$ 3,174,415	$ 673,015

(1) Mustang Island was reclassified from impairment to a dry hole.

(2) In November 2008, we released undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas in 2006, and recorded a $7.1 million exploration expense.

Costs Incurred in Oil and Gas Producing Activities:

	2008	2007	2006
Property Acquisitions			
Proved	$ 60,765,315	$ 238,036,360	$
Unproved	57,203,337	30,407,525	8,745,363
Development Costs	86,685,192	30,814,788	6,465,719

Exploration Costs	2,520,389	13,405,017	10,783,663
	$ 207,174,233	$ 312,663,690	25,994,745

These costs include oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses and geological and geophysical expenses.

The following table shows oil and gas property dispositions:

	2008	2007	2006
Oil and gas properties	$ 21,765,688	$	$
Accumulated depreciation, depletion and amortization	(1,659,588)		
Net oil and gas properties	$ 20,106,100	$	$

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The dispositions in 2008 resulted in a net gain of $15.2 million.

4. Acquisitions and Disposition of Oil and Gas Properties

Acquisition from Smith Production Inc.

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith Production Inc. (*Smith*) for a purchase price of $65.0 million with an effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.0 million for the period between the effective date and the closing date, the cash consideration was $58.0 million, subject to final adjustment, by the end of the first quarter of 2009. The assets acquired consist of a 25% non-operated working interest in Samano Field located in Starr and Hidalgo Counties, a 100% operated working interest in North Bob West Field in Zapata County and 100% operated working interests in Brushy Creek and Hope Fields in DeWitt County. We acquired an interest in over 16,000 gross acres with these fields, most of which is held by production.

The $58.0 million adjusted price, with adjustment to the reserves for approximately one Bcfe of production for the interim operations between the effective date and closing, represented a purchase cost of $2.82 per Mcf*e* for approximately 21 Bcfe of proved reserves and $8,300 per *Mcfe* of current average daily production. We financed this acquisition with cash flows from operations, proceeds from the sale of assets and from borrowings available under the senior revolving credit facility.

For the year ended December 31, 2008, seven months of revenues and expenses, $11.7 million and $3.7 million, respectively, were included in our financial results of operations.

Prospect Acquisitions

During the third and fourth quarters of 2008, we acquired approximately 11,876 net undeveloped acres in Sabine, Shelby and San Augustine Counties in Texas on which we will target the Haynesville Shale, James Lime, and Travis Peak formations. We are currently developing a drilling strategy for this acreage, including unit and well spacing, with the expectation that we will commence our first well during the third quarter of 2009. We intend to continue to acquire additional acreage that complements our existing position and expect to have an active drilling program in this area by mid-year 2010. We financed this acquisition with cash flows from operations and from borrowings available under the senior credit facility.

Fort Worth Barnet Shale Disposition

In January 2008, we and our operator-partner entered into a series of agreements to sell our interests in wells and undeveloped acreage in the Fort Worth Barnett Shale Play in Johnson and Tarrant Counties, Texas to another industry participant active in that area. We owned a 12.5% non-operated working interest in the assets being sold and had 1.5 Bcfe in proved reserves at December 31, 2007. The final total consideration paid by the buyer was based on existing wells and undeveloped acreage owned by us and our partner at the time of the final closing. Our share of the consideration received was approximately $34.4 million. Proceeds received for our interest were primarily used to repay amounts outstanding under our senior revolving credit facility and to help finance our acquisition of the properties from Smith. Our net book value of these assets sold was $18.8 million, which resulted in a gain of $15.6 million.

STGC Properties Acquisition

On May 8, 2007, we entered into a purchase agreement with EXCO and SGH (*EXCO Purchase Agreement*), pursuant to which we acquired, for $285.0 million in cash (excluding adjustments) and 750,000 shares of common stock, par value $0.001 per share (*Common Stock*) certain oil and natural gas properties and related assets in the STGC Properties held by SGH immediately before the closing of the acquisition. After considerations for typical closing adjustments, $229.0 million of the purchase price was allocated to proved properties and $28.6 million was allocated to unproved properties. The properties acquired include approximately 215 producing wells in over 30 fields. We have an average 65% working interest in the properties and operate more than 80% of the value acquired. The major producing fields acquired reside in Liberty and Lavaca Counties of the Upper Texas Gulf Coast, Brooks County of South Texas and Calcasieu Parish of South Louisiana. The properties and related assets were acquired through the conveyance of 100% of the membership interests of SGH from EXCO to us. The consolidated statements of operations include the results of operations of the STGC Properties from May 2007 to present.

The unaudited pro forma results presented below for the years ended December 31, 2007 and 2006 have been prepared to give effect to the STGC Properties acquisition described above on our results of operations as if it had been consummated on January 1, 2006. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or project our results of operations for any future date or period.

	2007	**2006**
	(Unaudited) *(In thousands, except share amounts)*	
Pro forma:		
Operating revenues	$ 154,068	$ 206,909
Income from operations	$ 56,647	$ 109,677
Net income	$ 9,305	$ 60,538
Basic earnings per share	$ 1.06	$ 14.29
Diluted earnings per share	$ 0.95	$ 6.33

5. Fair Values of Financial Instruments

Certain of our assets and liabilities are reported at fair value in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values for each class of financial instruments:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable. The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Derivative Instruments. Our derivative instruments consist of variable to fixed price commodity swaps, costless collars and interest rate swaps. We value our derivative instruments utilizing estimates of present value as calculated by the respective counter-party financial institutions and reviewed by management. See Note 7 Derivative Instruments for further information.

Fair value information for financial assets and liabilities that are measured at fair value each reporting period is as follows at December 31, 2008:

Fair Value Measurements Using

	Total Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Crude oil & natural gas swaps	$ 2,927,972	$	$ 2,927,972	$
Crude oil & natural gas collars	36,914,245		36,914,245	
Interest rate swaps	(5,685,526)		(5,685,526)	
	$ 34,156,691	$	$ 34,156,691	$

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SFAS 157, which we adopted as of January 1, 2008, establishes a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. We use Level 1 inputs when available as Level 1 inputs generally provide the most reliable evidence of fair value.

Debt The fair value of floating-rate debt is estimated using the carrying amounts because the interest rates paid on such debt are set for periods of three months or less. See Note 10 Debt for further information.

6. Impairments

In December 2008, we recorded a non-cash impairment expense of $10.2 million, primarily related to our Grand Lake Field in Southwest Louisiana. The impairment expense was a result of low commodity prices at year end and the underperformance of the Grand Lake Field. In September 2008, we recorded a non-cash impairment expense of $25.8 million related to our Madisonville Field in Central Texas. The Madisonville impairment relates primarily to the Rodessa formation within the Madisonville Field. Negative performance-related reserve revisions, including the abandonment of the Rodessa formation in the Johnston 2U well, triggered an evaluation of the Madisonville Field for impairment purposes. The high original cost of drilling and developing the field and the high cost of producing and processing sour gas, combined with lower commodity prices resulted in the recorded costs of this field exceeding the estimated future undiscounted cash flow of the reserves as of September 30, 2008.

Impairment expense was $4.4 million in 2007, primarily related to our Turkey Creek and Huff McFaddin properties, and $3.1 million in 2006, primarily related to our Iola property. Declining performance and lower gas prices at year end were contributing factors in these property impairments.

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7. Derivative Instruments

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our natural gas and crude oil production, to reduce our sensitivity to volatile commodity prices and with respect to portions of our debt, to reduce our sensitivity to volatile interest rates. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to commodity price and interest rate fluctuations. However, derivative arrangements limit the benefit of increases in the prices of natural gas, crude oil and natural gas liquids sales and limit the benefit of decreases in interest rates. Moreover, our derivative arrangements apply only to a portion of our production and our debt and provide only partial protection against declines in commodity prices and increases in interest rates. Such arrangements may expose us to risk of financial loss in certain circumstances. We continuously reevaluate our hedging programs in light of changes in production, market conditions, commodity price forecasts, capital spending and debt service requirements.

We used a mix of swaps and costless collars to accomplish our hedging strategy. We also constructively fixed the base LIBOR rate on $200.0 million of our variable rate debt by entering into interest rate swaps agreements.

The following derivative contracts were in place at December 31, 2008:

Crude Oil		**Volume/Month**		**Price/Unit**	**Fair Value**
Jan 2009-Dec 2009	Swap	5,200	Bbls	$74.20	$ 1,224,731
Jan 2009-Dec 2009	Collar	12,800	Bbls	Floor $66.55-$71.40 Ceiling	2,011,268
Jan 2009-Dec 2009	Collar	10,646	Bbls	Floor $115.00-$171.50 Ceiling	7,784,669
Jan 2010-Dec 2010	Swap	4,250	Bbls	$72.32	422,097
Jan 2010-Dec 2010	Collar	9,000	Bbls	Floor $65.28-$70.60 Ceiling	366,711
Jan 2010-Dec 2010	Collar	7,604	Bbls	Floor $110.00-$181.25 Ceiling	4,337,646
Jan 2011-Dec 2011	Swap	3,300	Bbls	$70.74	73,308
Jan 2011-Dec 2011	Collar	7,000	Bbls	Floor $64.50-$69.50 Ceiling	(159,439)
Natural Gas		**Volume/Month**		**Price/Unit**	
Jan 2009-Dec 2009	Swap	36,000	MMbtu	$8.32	950,951
Jan 2009-Dec 2009	Collar	475,000	MMbtu	Floor $7.90-$9.45 Ceiling	11,130,013
Jan 2009-Dec 2009	Collar	100,375	MMbtu	Floor $9.50-$18.70 Ceiling	4,265,493
Jan 2010-Dec 2010	Swap	29,000	MMbtu	$7.88	256,885
Jan 2010-Dec 2010	Collar	351,000	MMbtu	Floor $7.57-$9.05 Ceiling	3,432,247
Jan 2010-Dec 2010	Collar	85,167	MMbtu	Floor $9.00-$15.25 Ceiling	2,395,846
Jan 2011-Dec 2011	Collar	266,000	MMbtu	Floor $7.32-$8.70 Ceiling	1,349,791
Interest Rate		**Volume/Month**		**Fixed LIBOR Rate**	
Jan 2009-Dec 2010	Swap	$ 50,000,000		1.50%	(289,496)
Jan 2009-May 2011	Swap	$ 150,000,000		2.90%	(5,396,030)
		Total net fair value asset of derivative instruments			$ 34,156,691

The total net fair value asset for derivative instruments at December 31, 2008 was $34.2 million, and the total net fair value liability at December 31, 2007 was $15.3 million. As a result of these agreements, we recorded a non-cash unrealized gain, for unsettled contracts, of $49.4 million for the twelve months ended December 31, 2008, a non-cash unrealized loss of $18.2 million for the twelve months ended December 31, 2007. The estimated change in fair value of the derivatives is reported in Other Income (Expense) as unrealized gain (loss) on derivative instruments.

For natural gas and crude oil derivatives settled during 2008, we realized losses, reflected in operating revenues, of $9.3 million for the twelve months ended December 31, 2008. For natural gas and crude oil derivatives settled during 2007, we realized gains of $3.0 million for the twelve months ended December 31, 2007 and a non-cash unrealized gain of $6.1 million for the twelve months ended December 31, 2006. For natural gas and crude oil derivatives settled during 2006, we realized losses, reflected in operating revenues of $0.6 million for the twelve months ended December 31, 2006. For interest rate swaps, we realized losses, included in interest expense, of $4.0 million for the twelve months ended December 31, 2008. We realized gains, included in interest expense, of $0.2 million from interest rate swaps for the twelve months ended December 31, 2007.

8. Accrued Liabilities

Accrued liabilities consist of the following:

	December 31, 2008	December 31, 2007
Lease acquisition costs	$ 11,246,914	$
Capital drilling and operating costs	9,202,949	
Smith acquisition	1,291,847	
Accrued compensation	1,244,772	1,486,116
Interest and loan fees	988,521	1,530,627
Other	394,057	217,810
	$ 24,369,060	$ 3,234,553

9. Asset Retirement Obligations

A reconciliation of our asset retirement obligation liability is as follows:

	December 31, 2008	December 31, 2007
Balance beginning of year	$ 7,555,491	$ 4,215,205
Accretion expense	620,813	435,328
Liabilities incurred	4,191,364	3,184,079
Liabilities settled	(853,867)	(279,121)
Revisions	1,554,741	
Balance end of year	$ 13,068,542	$ 7,555,491

During 2008, we recognized additional liabilities incurred of $4.2 million, primarily related to new wells acquired through our acquisition and drilling programs. We also had $1.6 million in revisions primarily related to increased retirement costs at our Grand Lake facility in South Louisiana.

10. Debt

On May 8, 2007, we entered into a $400.0 million amended and restated credit agreement (the *Senior Revolving Credit Agreement*) with Wells Fargo Bank, National Association, as agent, and various other banks, which amended and restated our then existing senior secured revolving credit facility dated July 15, 2005, as amended. On May 31, 2007, the Senior Revolving Credit Agreement was amended to provide for up to a $5.0 million swing line facility. The Senior Revolving Credit Agreement has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2011. The Senior Revolving Credit Agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

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Borrowings under the Senior Revolving Credit Agreement are subject to a borrowing base limitation based on our proved natural gas, crude oil and natural gas liquids reserves. The borrowing base was reaffirmed at $200.0 million on November 1, 2008. Our borrowing base is redetermined semi-annually and is subject to one unscheduled redetermination between scheduled redeterminations, which may lead to a decrease in our borrowing base. We expect to undergo a borrowing base redetermination under our Senior Revolving Credit Agreement in the second quarter of 2009, and again in the fourth quarter of 2009. In the event a borrowing base redetermination results in a reduction of our borrowing base, further availability to borrow under the Senior Revolving Credit Agreement could be reduced. Due to the recent and continuous decline in commodity prices, we will likely incur a reduction in our borrowing base at the next redetermination date. Additionally, if a reduced borrowing base requires debt repayments, we may be required to curtail our capital program further, sell assets or raise additional equity capital to meet our obligations. In addition, it may be difficult for us to consummate any debt or equity financing in the near future to meet such obligations, particularly due to the current worldwide financial and credit crises and the decline in our stock price.

In addition, on May 8, 2007, we entered into a second lien credit agreement (the *Second Lien Credit Agreement*) with Credit Suisse, as agent, which provides for term loans to be made to us in a single draw in an aggregate principal amount of $150.0 million. The Second Lien Credit Agreement replaced our then existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing. The Second Lien Credit Agreement has a term of five years and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2012.

The Senior Revolving Credit Agreement and the Second Lien Credit Agreement (the *Credit Agreements*) are secured by a lien on substantially all of our assets, as well as a security interest in the stock of our subsidiaries. The obligations under the Second Lien Credit Agreement are subordinate and junior to those under the Senior Revolving Credit Agreement. Interest is payable on the Credit Agreements as borrowings mature and renew.

The Credit Agreements include usual and customary covenants for credit facilities of the respective types and sizes, including, among others, limitations on liens, hedging, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, certain leases and investments outside of the ordinary course of business, as well as events of default. The Credit Agreements also contain certain financial covenants, including (a) with respect to the Senior Revolving Credit Agreement, maintaining (i) a ratio of current assets (including borrowing base availability and excluding derivative instruments) to current liabilities (excluding current portion of long-term debt and derivative instruments) of at least 1.0 to 1.0, (ii) an interest coverage ratio of EBITDAX (earnings before interest, taxes, depreciation and amortization and exploration expense) to cash interest expense of at least 3.0 to 1.0 and (iii) a minimum leverage ratio of total debt to EBITDAX of 2.75 to 1.00 for the fiscal quarters ending after June 30, 2008 and (b) with respect to the Second Lien Credit Agreement, maintaining (i) a minimum leverage ratio of total debt to EBITDAX of 3.00 to 1.00 for the fiscal quarters ending after September 30, 2008 and (ii) a PV-10 Ratio (as defined in the Second Lien Credit Agreement) less than 1.50x for the period on or after January 1, 2008. EBITDAX is calculated without consideration of unrealized gains and losses related to stock derivatives accounted for under variable accounting rules or to commodity hedges. The PV-10 Ratio is the ratio of PV-10 Value (as defined) on the relevant date to Total Net Debt (as defined) on such date; provided that if the PV-10 Value calculated using only the estimated future revenues to be generated from proved developed producing reserves (the *PDP Component*, is less than 60% of the otherwise calculated total PV-10 Value, then for purposes of calculating the PV-10 Ratio, PV-10 Value is deemed to be the quotient of the PDP Component divided by 0.60. At December 31, 2008, we were in compliance with the Credit Agreements covenants.

Our debt consists of the following:

	December 31, 2008	December 31, 2007
Subordinated promissory notes to various unlocatable individuals	$ 50,000	$ 50,000
Notes payable to finance vehicles, payable in aggregate monthly installments of approximately $3,600, including interest of 5.99% to 10.49% at December 31, 2008 per annum; secured by the related equipment; due various dates through 2010	57,720	114,835
Senior Revolving Credit Agreement with a borrowing base of $200.0 million, secured by all of our assets, interest at the higher of prime or Federal Fund rate plus a margin of 0.50%, or, at the option of the holder, LIBOR plus a margin of 1.25% to 2.00% depending on the percent of the borrowing base utilized at the time of the credit extension, due and payable in full in May 2011	126,673,074	110,000,000
Second Lien Credit Agreement for a term loan in a single draw, secured by all of our assets, subordinate and junior to the Senior Revolving Credit Agreement, floating interest rates at LIBOR plus 5.75% or base rate plus 4.75%, maturing in May 2012	150,000,000	150,000,000
	276,780,794	260,164,835
Less current portion	(90,368)	(100,609)
Total long-term debt	$ 276,690,426	$ 260,064,226

Estimated annual maturities for long-term debt are as follows:

2009	$ 90,368
2010	17,352
2011	126,673,074
2012	150,000,000
2013	
	$ 276,780,794

11. Commitments and Contingencies

The following table provides our best estimate on certain of our obligations as of December 31, 2008:

	Long-Term Debt	Interest	Operating Leases	Asset Retirements	Executive Compensation	FIN 48[1]
2009	$ 90,368	$ 14,848,716	$ 2,641,835	$ 1,659,371	$ 1,516,300	$
2010	17,352	14,848,716	1,820,471	1,031,755	1,516,300	
2011	126,673,074	5,279,543	1,437,749	1,953,292	710,000	
2012	150,000,000	3,864,088	1,419,933	438,172		

2013			1,419,933	393,668		
Thereafter			118,328	7,592,284		
Total	$ 276,780,794	$ 38,841,063	$ 8,858,249	$ 13,068,542	$ 3,742,600	$ 518,219

(1) FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109 (*FIN 48*). We are unable to determine when this obligation may be required to be paid, if at all.

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Lease Obligations

We entered into a sublease agreement for new office space under an eighty-two (82) month lease that commenced in April 2007. We leased additional space in August 2008. Both leases expire in January 2014.

We have entered into various vehicle leases for periods ranging from 24 to 50 months. These contracts will expire at various times with the latest contract expiring in September 2010. We also have various other equipment leases that expire in 12 to 36 months, with the latest contract expiring in June 2011.

Total general and administrative rent expense for the years ended December 31, 2008, 2007 and 2006, were approximately $1.4 million, $0.4 million and $0.2 million, respectively. Total operational rent expense for the years ended December 31, 2008, 2007 and 2006, were approximately $3.4 million, $0.9 million and $1.0 million, respectively.

Litigation

From time to time, we are involved in litigation arising out of our operations or from disputes with vendors in the normal course of business. As of December 31, 2008, we are not currently engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material effect on our consolidated financial statements.

Employment Agreements

In December 2008, we entered into amended and restated employment agreements with our President/Chief Executive Officer and Senior Vice President/Chief Financial Officer. Each agreement has a term of three years with automatic yearly extensions unless we or the executive officer elects not to extend the agreement. These agreements provide for an annual base salary of $370,000 and $340,000, respectively. If the contracts are terminated by us without cause or by the employee for good reason, and the employee has been in compliance with employee contract terms, the employee may receive a cash payment equal to 2.99 times the sum of the current calendar year s base salary plus prior year s annual cash incentive bonus, health insurance benefits for 36 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

Also in December 2008, we entered into amended and restated employment agreements with our three other Senior Vice Presidents and entered into an employment agreement with our one Vice President. Each agreement has a term of two years with automatic yearly extensions unless we or the executive officer elects not to extend the agreement. These agreements provide for an annual base salary ranging from $186,300 to $220,000. If the contracts are terminated by us without cause or by the employee for good reason, and the employee has been in compliance with the employee contract terms, the employee is entitled to receive a cash payment equal to two times current year base salary plus prior year bonus, health insurance benefits for 24 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

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12. Stockholders Equity

	2008	2007
Preferred Stock		
Series G, par value $0.01; 81,000 shares authorized; 80,500 and 81,000 issued and outstanding at December 31, 2008 and 2007, respectively	$ 805	$ 810
Series H, par value $0.01; 6,500 shares authorized; 2,100 and 2,200 shares issued and outstanding at December 31, 2008 and 2007, respectively	21	22
	$ 826	$ 832
Common Stock		
Par value $0.001; 200,000,000 shares authorized; 5,787,287 and 5,127,937 shares issued as of December 31, 2008 and 2007, respectively	$ 5,808	$ 5,128
Treasury Stock		
At cost, 20,625 and zero shares as of December 31, 2008 and 2007, respectively	$ (250,594)	$

The 80,500 shares of our Series G Preferred Stock bear cumulative dividends of 8% per year, compounded quarterly, and have an aggregate liquidation preference of $40.3 million, excluding accumulated and undeclared dividends. For the first four years after issuance, we may defer the payment of dividends on the Series G Preferred Stock and these deferred dividends will also be convertible into our Common Stock at $9.00 per share. These dividends are not currently being accrued in our financial statements until such time as they are declared by the Board of Directors and become due and payable. In addition, the Series G Preferred Stock is entitled to vote on an as-converted basis with the holders of our Common Stock and, as a class, is entitled to nominate and elect a majority of the members of our Board of Directors. The Series G Preferred Stock is senior to all of our outstanding capital stock in liquidation preference.

The 2,100 shares of our Series H Preferred Stock are required to be paid a dividend of 40 shares of Common Stock per one share of Series H Preferred Stock per year. In addition, the Series H Preferred Stock is convertible into Common Stock at a conversion price of $3.50 per share. The Series H Preferred Stock has an aggregate liquidation value of $1.1 million and is senior to all of our outstanding capital stock in liquidation preference other than the Series G Preferred Stock.

All classes of preferred stockholders have a liquidation preference over common stockholders of $500 per preferred share, plus accrued dividends. Accumulated, unpaid and undeclared dividends at December 31, 2008 were $14.4 million (Series G $14.4 million; Series H $9,380). Once dividends are declared, they may be converted to approximately 1.6 million shares of Common Stock (Series G 1.6 million; Series H 2,680).

13. Share-Based Compensation

As of December 31, 2008, we had share-based compensation, which includes both stock options and restricted stock awarded to employees and directors. The following table reflects share-based compensation expense assuming a 36.5% effective tax rate for the years ended:

	December 31, 2008	December 31, 2007	December 31, 2006
Share-based compensation expense, net of tax $1,982,984, $1,725,277 and $1,339,014, respectively	$ 3,452,008	$ 3,003,387	$ 2,330,975
Basic income (loss) per share impact	$ (0.64)	$ (0.69)	$ (0.72)
Diluted income (loss) per share impact	$ (0.33)	$ (0.69)	$ (0.72)

Incentive Plans

In the third quarter 2008, our Board of Directors formally adopted an amendment to our performance based cash bonus plan and adopted a new performance based long term stock bonus plan for the benefit of all employees the Crimson Cash Incentive Bonus Plan (*CIBP*) and the Crimson Long-Term Incentive Plan (*LTIP*), respectively. Both plans, and specific targeted performance measures for the fiscal year 2008 under those plans, were previously approved by the Compensation Committee. Upon achieving the established performance levels, bonus awards are calculated as a percentage of base salary for the plan year. The plan awards are disbursed in the first quarter of the following year. Employees must be employed by us at the time that final plan awards are dispersed to be eligible.

The CIBP awards are paid out in cash (*Cash Awards*). The performance targets are evaluated on a quarterly basis and used to estimate the approximate expense earned to date. Approximately $1.2 million was recognized as compensation expense related to the Cash Awards for the twelve months ended December 31, 2008.

The LTIP bonus awards are paid half in the form of restricted Common Stock and half in the form of stock options (*Stock Awards*). The Stock Awards will vest 25% per year, over the first through fourth anniversaries from the date of grant, at which time 100% of all Stock Awards will be vested. The number of shares of restricted Common Stock and the number of shares underlying the stock options to be granted as Stock Awards will be determined based upon the fair market value of the Common Stock on the date of the grant in the first quarter 2009. The fair value of the stock options to be awarded as part of this plan will be determined through use of the Black-Scholes valuation model. The Stock Awards to be granted pursuant to this plan will be granted under the existing amended and restated 2005 Stock Incentive Plan. The Board of Directors and a majority of the Common Stock equivalents entitled to vote, approved; among other things, an increase in the number of available shares of Common Stock issuable under the amended and restated 2005 Stock Incentive Plan by 1,000,000 shares.

In March 2009, the Board of Directors approved the awarding of approximately 1.1 million shares to our employees under the performance-based Long-Term Incentive Plan (*LTIP*) for the 2008 calendar year. After the issuance of these stock awards, approximately 0.4 million stock awards will remain in the plan. Due to the recent decline in our stock price, the Board of Directors suspended the LTIP for 2009. Any share-based bonus awards for fiscal year 2009 will be awarded at the discretion of the Board of Directors.

Stock Options

Effective July 15, 2004, we implemented our 2004 Stock Option and Compensation Plan (*2004 Plan*). As of December 31, 2008, there were options to purchase 44,300 shares of Common Stock outstanding and exercisable under the 2004 Plan. Effective February 28, 2005, we established our 2005

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Stock Incentive Plan (*2005 Plan*) and authorized the issuance of up to approximately 2.9 million shares of Common Stock pursuant to awards under the plan. In the third quarter 2008, our Board of Directors and a majority of our stockholders approved an amendment and restatement of our 2005 Stock Incentive Plan that provided for an increase in the number of shares of Common Stock available for award under our 2005 Stock Incentive Plan to approximately 3.9 million shares. Approximately 1.6 million (0.8 million vested) stock options and 0.5 million restricted shares were outstanding under this plan at December 31, 2008. Option awards outstanding under both plans have exercise prices ranging from $4.50 to $16.55 per share. At December 31, 2008, we had approximately 1.5 million shares of Common Stock available for future grant under the plan.

Pursuant to SFAS 123(R) for options issued under our 2005 plan, we recorded $5.0 million, $4.2 million and $3.7 million in expense (included in general and administrative expense on the Consolidated Statements of Operations) for the years ended December 31, 2008, 2007 and 2006, respectively, and an estimated $2.5 million will be expensed over the remaining vesting period.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model. Assumptions used in the valuation are disclosed in the following table. Expected volatilities are based on historical volatility of our stock with a look back period based on the expected term. The expected dividend yield is zero as we have never declared dividends on our Common Stock. The expected term of options granted represents the period of time that the options are expected to be outstanding. The risk-free rate is based on U.S. Treasury bills with a duration equal or close to the expected term of the options at the time of grant. The forfeiture rate is zero and is based on historical forfeiture rates.

	2008	**2007**	**2006**
Expected volatility	58.61%	87.46%	92.33%
Risk-free rate	3.38%	4.12%	4.04%
Expected dividend yields	%	%	%
Expected term (in years)	6.0	6.0	6.0

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The following table summarizes stock option activity for the three years ended December 31, 2008:

	Number of Shares Underlying Options	Weighted Average Exercise Price
Outstanding at December 31, 2005	2,411,000	$ 13.60
Granted	51,000	13.12
Exercised	(10,700)	4.50
Expired	(6,500)	8.30
Forfeited	(103,000)	14.89
Outstanding at December 31, 2006	2,341,800	13.62
Granted	393,000	6.86
Exercised	(1,000)	4.50
Expired	(3,500)	7.50
Outstanding at December 31, 2007	2,730,300	12.76
Granted	126,500	12.29
Exercised	(75,000)	5.02
Expired	(27,000)	8.86
Exchanged	(1,091,260)	17.00
Outstanding at December 31, 2008	1,663,540	$ 10.39
Exercisable at December 31, 2008	811,471	$ 10.78

The weighted-average grant date fair value of options granted during the years ended December 31, 2008, 2007 and 2006 was $7.07, $4.53 and $7.13, respectively. The total intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 was approximately $0.5 million, $5,425 and $33,360 respectively. The weighted average remaining life for outstanding and exercisable stock options at December 31, 2008 was 6.9 years and 6.1 years, respectively. The aggregate intrinsic values for outstanding and exercisable stock options at December 31, 2008 were zero.

Restricted Stock Awards

In the fourth quarter 2008, we issued 12,280 shares of unvested Common Stock, pursuant to restricted stock awards in exchange for the forfeiture of 24,560 substantially unvested stock option grants. The fair value of the unvested Common Stock was calculated as approximately $88,000 on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was approximately $37,000 immediately prior to the forfeiture. Under SFAS 123R, the sum of the incremental value of the new award over the forfeited options, approximately $52,000, and the unrecognized compensation cost for the original award as of the exchange date, approximately $45,000, are being amortized using the straight line method over the new vesting period of five years, or approximately $1,600 a month.

In the third quarter 2008, we issued 1,538 shares of Common Stock pursuant to restricted stock awards to two members of our board of directors as compensation pursuant to the Director Compensation Plan. In the third quarter 2008, we also issued 533,350 shares of unvested Common Stock pursuant to restricted stock awards in exchange for the forfeiture of 1,066,700 substantially vested stock option grants. The fair value of the unvested Common Stock was calculated as $4.9 million on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was $4.3 million immediately prior to the forfeiture. Under SFAS 123R, the sum of the incremental value of the new award over the forfeited options, $0.6 million, and the unrecognized compensation cost for the original award as of the exchange date, $1.4 million, are being amortized using the straight line method over the new vesting period of five years, or approximately $32,000 a month.

On September 28, 2007, we issued 250,000 shares of restricted Common Stock, pursuant to restricted stock awards, to our executive officers in recognition of their performance in consummating the STGC Properties acquisition and in recognition of the need to make appropriate adjustments to compensation commensurate with that currently provided to similarly situated executives in this highly competitive industry, and to provide equity incentives to those officers to remain with Crimson to maximize return to our stockholders. The restricted stock will vest over four years. In 2008, 82,500 shares of Common Stock were vested, of which 20,625 shares were acquired by us to satisfy the employees tax liability resulting from the vesting of these shares, with the remaining shares being released to the employees. None of the awards vested in 2007. We expensed $191,406 during the year ended December 31, 2007 and $459,375 during the year ended December 31, 2008. On May 10, 2007, we issued 2,818 restricted shares of our Common Stock to certain of our directors upon reelection to the board, pursuant to the director compensation plan. The stock vested on May 10, 2008. We expensed $12,796 during the year ended December 31, 2007 and expensed $7,204 during the year ended December 31, 2008.

On May 12, 2006, we issued 2,410 restricted shares of our Common Stock to our directors as compensation. The stock vested on May 12, 2007. We expensed $12,742 during the year ended December 31, 2006 and expensed $7,258 during the year ended December 31, 2007. On February 28, 2006, we also issued 26,234 restricted shares of our Common Stock to members of our management in lieu of cash bonuses. The stock vested on February 28, 2007. We expensed $163,960 during the year ended December 31, 2006, and expensed $32,790 during the year ended December 31, 2007.

We have not incurred any forfeiture related to the restricted stock awards issued.

Restricted stock activity for the three years ended December 31, 2008 is summarized below:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1, 2006	3,410	$ 8.80
Granted	28,644	7.57
Vested	(3,410)	8.80
Non-vested as of December 31, 2006	28,644	7.57
Granted	252,818	7.35
Vested	(28,644)	7.57
Non-vested as of December 31, 2007	252,818	7.35
Granted	547,168	9.12
Vested	(85,318)	7.34
Non-vested as of December 31, 2008	714,668	$ 8.70

Certain of these restricted stock awards were issued separately from the 2005 Plan.

Stock Warrants

We have issued a number of stock warrants for a variety of reasons, including compensation to employees, inducements related to the issuance of debt and for the payment of goods and services.

Following is a schedule by year of the activity related to stock warrants, including weighted-average exercise prices of warrants in each category:

	2007		2006	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	0.10	3,000	7.40	147,000
Warrants issued				
Warrants exercised or expired	0.10	(3,000)	7.50	(144,000)
Balance, December 31			0.10	3,000

No warrants have been issued since 2005. All warrants have expired.

14. Income (Loss) Per Common Share

The following is a reconciliation of the numerators and denominators used in computing income (loss) per share:

	2008	2007	2006
Net income (loss)	$ 46,203,218	$ (430,517)	$ 1,858,944
Preferred stock dividends	(4,234,050)	(4,453,872)	(3,648,925)
Net income (loss) available to common stockholders	$ 41,969,168	$ (4,884,389)	$ (1,789,981)
Weighted-average number of shares of Common Stock basic (denominator)	5,371,377	4,330,282	3,231,000
Income (loss) per share basic	$ 7.81	$ (1.13)	$ (0.55)
Weighted-average number of shares of Common Stock diluted (denominator)	10,360,348	4,330,282	3,231,000
Income (loss) per share diluted	$ 4.46	$ (1.13)	$ (0.55)

The numerator for basic earning per share is income (loss) available to common stockholders. The numerator for diluted earnings per share is net income in 2008 and net loss available to common stockholders in 2007 and 2006, due to antidilution.

Potential dilutive securities (vested stock options, vested restricted stock, vested stock warrants and convertible preferred stock) in 2007 and 2006 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. The potentially dilutive shares would have been 5,186,148 shares and 5,581,202 shares in 2007 and 2006, respectively.

15. Income Taxes

Income tax expense (benefit) for 2008, 2007 and 2006 consist of the following:

	2008	2007	2006
Current tax expense	$ 574,752	$	$
Deferred tax expense (benefit)	26,116,055	(410,361)	1,425,305
Income tax expense (benefit)	$ 26,690,807	$ (410,361)	$ 1,425,305

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The following is a reconciliation of effective income tax rates by applying the federal statutory rate of 35% to the income and loss for the years ended December 31, 2008, 2007 and 2006, respectively:

	2008		2007		2006	
Income (Loss) Before Income Taxes	$ 72,894,025		$ (840,878)		$ 3,284,249	
Income Tax Expense (Benefit) at Statutory Rate	$ 25,512,909	35.0%	$ (294,307)	35.0%	$ 1,149,487	35.0%
Effect for Permanent Items	307,425	0.4%	35,901	–4.3%	(14,339)	-0.4%
State Taxes and Other	870,473	1.2%	(151,955)	18.1%	290,157	8.8%
Income Tax Expense (Benefit)	$ 26,690,807	36.6%	$ (410,361)	48.8%	$ 1,425,305	43.4%

As of December 31, 2008, we had net operating loss carryforwards of approximately $15.6 million, which are available to reduce future taxable income and the related income tax liability. We expect we will not be able to utilize carryforwards of approximately $9.1 million due to the limitations of Internal Revenue Code Section 382. The net operating loss carryforward expires at various dates through 2026.

Significant components of the Company s deferred tax assets and liabilities are as follows:

	December 31, 2008	December 31, 2007
Deferred tax assets		
Net operating loss carryforwards	$ 5,599,532	$ 11,470,413
Income tax credits	397,767	117,695
Derivative instruments		5,973,543
Deferred compensation	5,032,928	3,175,717
Other	130,910	688,917
Deferred tax assets before valuation allowance	11,161,137	21,426,285
Valuation Allowance	(3,260,875)	(3,442,034)
Net deferred tax assets	7,900,262	17,984,251
Deferred tax liabilities		
Oil and gas properties	(19,712,706)	(16,361,040)
Derivative instruments	(12,128,079)	
Deferred tax liabilities	(31,840,785)	(16,361,040)
Net deferred tax (liabilities) assets	$ (23,940,523)	$ 1,623,211

Our deferred taxes increased by approximately $25.6 million during 2008. Deferred tax assets are shown net of a $3.3 million valuation allowance.

We adopted the provisions of the FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109 (*FIN 48*) on January 1, 2007, which resulted in a reduction to stockholders equity of $354,168. On the date of adoption, we had $518,219 of unrecognized tax benefits. There were no changes to this unrecognized tax benefit in 2007 and 2008.

Our policy is to recognize interest and penalties related to uncertain tax positions as income tax expense. We recorded no potential interest expense and penalties related to unrecognized tax benefits associated with uncertain tax positions recognized in our provision for income taxes. To the

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extent that interest and penalties are assessed with respect to uncertain tax positions, amounts accrued will be reflected as additional income tax expense.

Our tax returns are subject to periodic audits by the various jurisdictions in which we operate. These audits can result in adjustments of taxes due or adjustments of the net operating loss carryforwards that are available to offset future taxable income.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2008. However, due to the complexity of the application of tax law and regulations, it is possible that the ultimate resolution of these positions may result in liabilities which could be materially different from these estimates.

16. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2008 and 2007 follows:

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2008				
Net sales	$ 45,036,091	$ 53,013,341	$ 53,751,791	$ 34,967,050
Income (loss) from operations	35,400,343	24,745,879	(4,316,240)	(9,734,688)
Net income (loss) available to common stockholders	(361,339)	(26,618,441)	49,160,564	19,788,384
Income(loss)per common share				
Basic	$ (0.07)	$ (5.15)	$ 9.19	$ 3.41
Diluted	$ (0.07)	$ (5.15)	$ 4.87	$ 1.97
Weighted average shares outstanding				
Basic	5,149,341	5,173,463	5,351,146	5,806,988
Diluted	5,149,341	5,173,463	10,317,629	10,580,260
2007				
Net sales	$ 4,547,126	$ 26,658,550	$ 38,008,650	$ 40,328,882
Income (loss) from operations	(557,405)	9,897,272	15,672,330	8,604,102
Net income (loss) available to common stockholders	(2,458,088)	3,393,147	4,488,012	(10,307,460)
Income(loss)per common share				
Basic	$ (0.74)	$ 0.84	$ 0.93	$ (2.02)
Diluted	$ (0.74)	$ 0.45	$ 0.63	$ (2.02)
Weighted average shares outstanding				
Basic	3,333,806	4,046,510	4,827,731	5,091,206
Diluted	3,333,806	9,369,974	9,745,276	5,091,206

17. Oil and Gas Reserves (unaudited)

All information set forth herein relating to our proved reserves, estimated future net cash flows and present values is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC s guidelines, our estimates of proved reserves and the future net revenues from which present values are derived are made using year end natural gas and crude oil sales prices held constant throughout the life of the properties. Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

The following unaudited table sets forth proved natural gas, crude oil and natural gas liquids reserves, all within the United States, at December 31, 2008, 2007 and 2006, together with the changes therein. Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC properties in May 2007.

	Natural Gas (Mcf)	Crude Oil (Bbls)	Natural Gas Liquids (Bbls)	Total (Mcfe)
QUANTITIES OF PROVED RESERVES:				
Balance December 31, 2005	24,650,263	2,707,523		40,895,401
Revisions	882,566	(21,823)		751,628
Extensions, discoveries and additions	7,397,142			7,397,142
Production	(1,542,423)	(184,881)		(2,651,709)
Balance December 31, 2006	31,387,548	2,500,819		46,392,462
Revisions[(1)]	(21,184,471)	(521,000)	3,692,173	(2,157,433)
Extensions, discoveries and additions	7,716,613	194,846	183,699	9,987,883
Purchase	82,386,946	1,137,402		89,211,358
Sales				
Production	(9,067,777)	(408,864)	(285,907)	(13,236,403)
Balance December 31, 2007	91,238,859	2,903,203	3,589,965	130,197,867
Revisions[(2)]	(9,678,571)	(408,055)	(752,440)	(16,641,541)
Extensions, discoveries and additions	11,948,600	470,828	603,414	18,394,052
Purchase	17,311,835	107,332	474,642	20,803,679
Sales	(1,516,480)	(11,440)		(1,585,120)
Production	(13,135,509)	(498,143)	(516,352)	(19,222,479)
Balance December 31, 2008	96,168,734	2,563,725	3,399,229	131,946,458
PROVED DEVELOPED RESERVES:				
December 31, 2006	27,145,360	2,249,424		40,641,904
December 31, 2007	67,996,730	2,266,017	2,683,678	97,694,900
December 31, 2008	66,711,779	1,615,974	2,422,878	90,944,891

(1) The reporting of net NGL sales volumes began in mid-year 2007 following the close of the EXCO acquisition. The end of year 2007 reserve report was updated to reflect this change in reporting. The resulting changes in 2007 volumes for natural gas and natural gas liquids are reflected in revisions.

(2)

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.

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Standardized measure of discounted future net cash flows relating to proved reserves:

	2008	2007	2006
Future cash inflows	$ 749,121,400	$ 1,125,374,500	$ 313,312,927
Future production and development costs			
Production	214,969,100	258,028,900	108,693,762
Development	86,068,300	65,779,100	26,229,488
Future cash flows before income taxes	448,084,000	801,566,500	178,389,677
Future income taxes	(46,695,950)	(198,920,968)	(43,534,046)
Future net cash flows after income taxes	401,388,050	602,645,532	134,855,631
10% annual discount for estimated timing of cash flows	(140,485,818)	(203,122,453)	(57,442,604)
Standardized measure of discounted future net cash flows	$ 260,902,233	$ 399,523,079	$ 77,413,027

The following reconciles the change in the standardized measure of discounted future net cash flows:

	2008	2007	2006
Beginning of year	$ 399,523,079	$ 77,413,027	$ 118,397,139
Changes from:			
Purchases of proved reserves	69,628,594	324,427,750	
Sales of producing properties	(2,817,597)		
Extensions, discoveries and improved recovery, less related costs	77,931,000	43,636,200	12,096,684
Sales of natural gas, crude oil and natural gas liquids produced, net of production costs	(148,588,993)	(85,425,742)	(13,950,146)
Revision of quantity estimates[(1)]	(44,029,057)	(15,028,200)	1,980,452
Accretion of discount	39,952,308	10,240,157	17,156,239
Change in income taxes	101,522,054	(88,340,375)	28,176,711
Changes in estimated future development costs	(32,461,195)	(8,693,224)	(946,764)
Development costs incurred that reduced future development costs	20,342,054	20,561,154	6,465,719
Change in sales and transfer prices, net of production costs	(227,731,733)	82,348,797	(75,110,065)
Changes in production rates (timing) and other	7,631,719	38,383,535	(16,852,942)
End of year	$ 260,902,233	$ 399,523,079	$ 77,413,027

(1)

Periodic revisions to the quantity estimates 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.

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	September 30, 2009 *(Unaudited)*	**December 31, 2008**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$	$
Accounts receivable, net of allowance	12,403,474	21,078,815
Prepaid expenses	3,849	77,293
Derivative instruments	17,121,267	25,191,445
Total current assets	29,528,590	46,347,553
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	601,046,541	584,093,885
Other property and equipment	3,365,032	3,282,088
Accumulated depreciation, depletion and amortization	(179,175,724)	(138,220,237)
Total property and equipment, net	425,235,849	449,155,736
NONCURRENT ASSETS		
Deposits	104,697	104,697
Debt issuance cost, net	3,331,976	2,890,094
Deferred charges		1,324,907
Derivative instruments	4,279,665	11,722,802
Total noncurrent assets	7,716,338	16,042,500
TOTAL ASSETS	$ 462,480,777	$ 511,545,789
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Current portion of long-term debt	$ 1,525,583	$ 90,368
Accounts and revenues payable	20,513,642	47,726,858
Income taxes payable	341,851	546,944
Accrued liabilities	8,912,643	24,369,060
Asset retirement obligations	2,161,914	1,659,371
Derivative instruments	3,098,405	1,265,801
Deferred tax liability, net	4,839,599	8,331,208
Total current liabilities	41,393,637	83,989,610
NONCURRENT LIABILITIES		

Long-term debt, net of current portion	290,000,788	276,690,426
Asset retirement obligations	12,394,368	11,409,171
Derivative instruments	1,383,745	1,491,755
Deferred tax liability, net	10,051,928	15,609,315
Other noncurrent liabilities	713,806	732,709
Total noncurrent liabilities	314,544,635	305,933,376
Total liabilities	355,938,272	389,922,986
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock (see Note 7)	826	826
Common stock (see Note 7)	6,483	5,808
Additional paid-in capital	97,565,970	95,676,875
Retained earnings	9,352,931	26,189,888
Treasury stock (see Note 7)	(383,705)	(250,594)
Total stockholders equity	106,542,505	121,622,803
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 462,480,777	$ 511,545,789

The Notes to Consolidated Financial Statements are an integral part of these statements.

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(Unaudited)			
OPERATING REVENUES				
Natural gas sales	$ 16,426,246	$ 33,826,275	$ 55,135,137	$ 92,074,941
Crude oil sales	6,709,774	11,389,585	21,518,736	34,150,048
Natural gas liquids sales	3,616,522	7,901,683	9,089,086	24,687,092
Operating overhead and other income	147,862	634,248	508,249	889,142
Total operating revenues	26,900,404	53,751,791	86,251,208	151,801,223
OPERATING EXPENSES				
Lease operating expenses	3,879,621	5,653,989	13,517,664	15,362,455
Production and ad valorem taxes	1,563,460	4,819,558	6,060,579	14,355,289
Exploration expenses	687,613	1,044,499	2,873,255	1,877,382
Depreciation, depletion and amortization	13,400,031	13,159,886	41,599,314	36,029,611
Impairment of oil and gas properties		25,798,755		25,798,755
General and administrative	3,836,194	7,591,344	13,381,282	17,819,461
Loss (gain) on sale of assets			18,925	(15,271,712)
Total operating expenses	23,366,919	58,068,031	77,451,019	95,971,241
INCOME (LOSS) FROM OPERATIONS	3,533,485	(4,316,240)	8,800,189	55,829,982
OTHER (EXPENSE) INCOME				
Interest expense	(6,633,642)	(5,540,319)	(16,349,300)	(15,871,096)
Other financing cost	(382,159)	(339,480)	(1,109,805)	(1,174,013)
Unrealized gain (loss) on derivative instruments	(9,929,947)	88,901,338	(17,237,909)	1,664,541
Total other (expense) income	(16,945,748)	83,021,539	(34,697,014)	(15,380,568)
INCOME (LOSS) BEFORE INCOME TAXES	(13,412,263)	78,705,299	(25,896,825)	40,449,414
Income tax benefit (expense)	4,826,137	(28,461,407)	9,080,238	(15,104,519)
NET INCOME (LOSS)	(8,586,126)	50,243,892	(16,816,587)	25,344,895
Dividends on preferred stock	(1,156,163)	(1,083,328)	(3,353,150)	(3,164,111)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (9,742,289)	$ 49,160,564	$ (20,169,737)	$ 22,180,784

NET INCOME (LOSS) PER SHARE								
Basic	$	(1.51)	$	9.19	$	(3.20)	$	4.25
Diluted	$	(1.51)	$	4.87	$	(3.20)	$	2.46
WEIGHTED AVERAGE SHARES OUTSTANDING								
Basic		6,444,013		5,351,146		6,301,280		5,225,113
Diluted		6,444,013		10,317,629		6,301,280		10,289,138

The Notes to Consolidated Financial Statements are an integral part of these statements

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2009

	Number of Shares				Additional			Total
	Preferred Stock	Common Stock	Preferred Stock	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Stockholde Equity
					(Unaudited)			
ANCE, DECEMBER 008	82,600	5,787,287	$ 826	$ 5,808	$ 95,676,875	$ 26,189,888	$ (250,594)	$ 121,622,
e-based compensation		668,690		669	1,868,731			1,869,
mon stock issued as ends on preferred		6,300		6	20,364	(20,370)		
ent period net loss						(16,816,587)		(16,816,
sury stock		(40,713)					(133,111)	(133,
ANCE, SEPTEMBER 009	82,600	6,421,564	$ 826	$ 6,483	$ 97,565,970	$ 9,352,931	$ (383,705)	$ 106,542,

The Notes to Consolidated Financial Statements are an integral part of these statements.

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CRIMSON EXPLORATION INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2009	2008
	(Unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (16,816,587)	$ 25,344,895
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	41,599,314	36,029,610
Settlement of asset retirement obligations	(361,239)	(421,600)
Stock compensation expense	1,869,400	4,450,871
Amortization of debt issuance cost	945,313	833,556
Deferred charges	1,324,907	(718,768)
Deferred income taxes (benefit)	(9,595,940)	14,919,519
Dry holes, abandoned property, impaired assets	221,960	25,798,755
(Gain) loss on sale of assets	18,925	(15,271,712)
Unrealized loss (gain) on derivative instruments	17,237,909	(1,664,541)
Changes in operating assets and liabilities:		
Decrease in accounts receivable	8,675,339	1,986,366
(Increase) decrease in prepaid expenses	73,444	(201,562)
Increase (decrease) in accounts payable and accrued liabilities	(42,440,824)	5,823,502
Net cash provided by operating activities	2,751,921	96,908,891
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from sale of assets	24,327	34,918,332
Capital expenditures	(16,545,051)	(82,577,152)
Acquisition of oil and gas properties	493,532	(58,031,525)
Deposits		(5,906)
Net cash used in investing activities	(16,027,192)	(105,696,251)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from exercise of common stock options		346,500
Purchase of treasury stock	(133,111)	
Proceeds from debt	91,373,659	122,169,922
Payments on debt	(76,578,082)	(108,206,369)
Debt issuance cost	(1,387,195)	
Net cash provided by financing activities	13,275,271	14,310,053
INCREASE IN CASH AND CASH EQUIVALENTS		5,522,693
CASH AND CASH EQUIVALENTS,		

Beginning of period				4,882,511
CASH AND CASH EQUIVALENTS, End of period	$		$	10,405,204
Cash paid for interest	$	14,484,741	$	17,378,802
Cash paid for income taxes	$	539,671	$	185,000

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. ORGANIZATION AND NATURE OF OPERATIONS

Crimson Exploration Inc., together with its subsidiaries (*Crimson* , *we* , *our* , *us*), is an independent natural gas and crude oil company engaged in the acquisition, development, exploitation and exploration of natural gas and crude oil properties, primarily in the onshore U.S. Gulf Coast and South Texas regions.

2. BASIS OF PRESENTATION

Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (*U.S.*) for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and notes required by U.S. generally accepted accounting principles (*GAAP*) for complete financial statements. The accompanying consolidated financial statements at September 30, 2009 (unaudited) and December 31, 2008 and for the three and nine months ended September 30, 2009 (unaudited) and 2008 (unaudited) contain all normally recurring adjustments considered necessary, in the opinion of management, for a fair presentation of our financial position, results of operations and cash flows for such periods. Operating results for the nine months ended September 30, 2009 are not necessarily indicative of the results that may be expected for the year ending December 31, 2009. These unaudited consolidated financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in our annual report on Form 10-K for the year ended December 31, 2008.

The accompanying financial statements include Crimson Exploration Inc. and its wholly-owned subsidiaries: Southern G Holdings, LLC, acquired May 8, 2007, and merged with Crimson Exploration Operating, Inc. on January 1, 2008, Crimson Exploration Operating, Inc., formed January 5, 2006 and LTW Pipeline Co., formed April 19, 1999. All material intercompany transactions and balances are eliminated upon consolidation. Certain reclassifications were made to previously reported amounts to make them consistent with the current presentation format.

Accounting Standards Codification On July 1, 2009, the Financial Accounting Standards Board (*FASB*) instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The FASB *Accounting Standards Codification™* (*ASC*) is now the single authoritative source for GAAP. Although the implementation of ASC had no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Adoption of ASU 2009-05 In August 2009, the Financial Accounting Standards Board (*FASB*) issued Accounting Standards Update (*ASU*) No. 2009-05, *Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value.* ASU 2009-05 provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. We adopted ASU No. 2009-05 (FASB ASC 820-10) as of September 30, 2009. The adoption of this statement did not have an impact on our financial position or results of operations.

Subsequent Events We adopted the Financial Accounting Standards Board (*FASB*) Statement No. 165, *Subsequent Events* , which is now incorporated into ASC Topic No. 855 (*ASC 855*) as of June 30, 2009. ASC 855 requires entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. The adoption of this statement did not have a material impact on our financial position or results of operations. We completed our review and analysis of potential subsequent events, as of

November 16, 2009, the date these financial statements were issued. See Note 11- Subsequent Events for additional disclosures.

Interim Disclosures about Fair Value of Financial Instrument We adopted FSP SFAS 107-1 and APB 28-1 Interim Disclosures about Fair Value of Financial Instruments , which is now incorporated into ASC Topic No. 825 (*ASC 825*) as of June 30, 2009. This statement increases the frequency of fair value disclosures to a quarterly instead of annual basis. The guidance relates to fair value disclosures for any financial instruments that are not currently reflected on the balance sheet at fair value. The adoption of this statement did not have a material impact on our financial position or results of operations.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly We adopted the FSP SFAS 157-4 Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly which is now incorporated into ASC Topic No. 820 (*ASC 820*) as of June 30, 2009. ASC 820 provides guidelines for a broad interpretation of when to apply market-based fair value measures. It reaffirms management s need to use judgment to determine when a market that was once active has become inactive and in determining fair values in markets that are no longer active.

Disclosure about Derivative Instruments and Hedging Activities We adopted FASB Statement No. 161, Disclosure about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 which is now incorporated into ASC Topic No. 815 (*ASC 815*) as of January 1, 2009. ASC 815 amends and expands the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments; (ii) how derivative instruments and related hedged items are accounted for; and (iii) how derivative instruments and related hedged items affect an entity s financial position, results of operations and cash flows. See Note 5 Derivative Instruments for these additional disclosures. The adoption of this statement did not have an impact on our financial position or results of operations.

Business Combinations We adopted SFAS No. 141 (Revised 2007) Business Combinations which is now incorporated into ASC Topic No. 805 *(ASC 805*) as of January 1, 2009. The revision broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, this statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. The adoption of this statement has not had an impact on our financial position or results of operations, because we have not yet had any business combinations in 2009.

Effective Date of FASB Statement No. 157 We also adopted FSP SFAS 157-2, Effective Date of FASB Statement No. 157 , which is also now incorporated into ASC Topic No. 820 as of January 1, 2009. The effective date was deferred for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually) to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. See Note 4 Fair Value Measurements for additional disclosures. The adoption of this statement did not have a material impact on our financial position or results of operations.

3. OIL AND GAS PROPERTIES

Acquisition from Smith Production Inc.

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith Production Inc. (*Smith*) for a purchase price of $65.0 million with an economic effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.4 million for the period between the effective date and the closing date, the cash consideration was approximately $57.6 million.

Fort Worth Barnett Shale Disposition

In January 2008, we and our operator-partner entered into a series of agreements to sell our interests in wells and undeveloped acreage in the Fort Worth Barnett Shale Play in Johnson and Tarrant counties, Texas to another industry participant active in that area. We owned a 12.5% non-operated working interest in the assets being sold and had 1.5 Bcfe in proved reserves at December 31, 2007. The final total consideration paid by the buyer was based on existing wells and undeveloped acreage owned by us and our partner at the time of the final closing. Our share of the consideration received was approximately $34.4 million. Proceeds received for our interest were primarily used to repay amounts outstanding under our senior secured revolving credit facility and to help finance our acquisition of the properties from Smith. Our net book value of these assets sold was $18.8 million, which resulted in a gain of $15.6 million.

4. FAIR VALUE MEASUREMENTS

We use a fair value hierarchy which prioritizes the inputs to valuation techniques for measuring fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. We use Level 1 inputs when available, as Level 1 inputs generally provide the most reliable evidence of fair value.

Certain of our assets and liabilities are reported at fair value in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values for each class of financial instruments:

Cash, Cash Equivalents, Accounts Receivable and Accounts Payable. The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments. Our allowance for doubtful accounts as of September 30, 2009 and December 31, 2008 remains at $0.2 million.

Derivative Instruments. Our derivative instruments consist of variable to fixed price commodity swaps, costless collars and interest rate swaps. We value our derivative instruments utilizing estimates of present value as calculated by the respective counterparty financial institutions and reviewed by management. See Note 5 Derivative Instruments for further information. Fair value information for assets and liabilities that are measured at fair value is as follows at September 30, 2009:

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Crude oil & natural gas swaps	$ 752,273	$	$ 752,273	$
Crude oil & natural gas collars	21,400,932		21,400,932	
Interest rate swaps	(5,234,423)		(5,234,423)	
Totals	$ 16,918,782	$	$ 16,918,782	$

Asset Impairments We review a proved oil and gas property for impairment when events and circumstances indicate a significant decline in the recoverability of the carrying value of such property. If events indicate a significant decline in the recoverability of such property, we estimate the future cash flows expected in connection with the property and compare such future cash flows to the carrying amount of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management s expectations for the future and include estimates of future oil and gas production, commodity prices based on commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. We had no asset impairments in the nine months ended September 30, 2009.

Debt The fair value of debt approximates the carrying amounts on such debt. Interest rates are based on Prime or LIBOR rates at the time the loans are renewed. See Note 6 Debt for further information.

Asset Retirement Obligations We estimate the fair values of asset retirement obligations (*AROs*) based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates.

	Total	**Fair Value Measurements Using**		
	Carrying Value	**Level 1**	**Level 2**	**Level 3**
Asset retirement obligations	$ 14,556,282	$	$	$ 14,556,282

Asset Retirement Obligations Rollforward

Beginning January 1, 2009 liability	$ 13,068,542
Additions	103,691
Accretion	643,825
Revisions	1,112,951
Properties sold	(11,488)
Plugging and abandonment activity	(361,239)
Ending September 30, 2009 liability	$ 14,556,282

5. DERIVATIVE INSTRUMENTS

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our natural gas and crude oil production, to reduce our sensitivity to volatile commodity prices, and with respect to portions of our debt, to reduce our sensitivity to volatile interest rates. None of our derivative instruments are designated as cash flow hedges. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to commodity price and interest rate fluctuations. However, derivative arrangements limit the benefit of increases in the prices of natural gas, crude oil and natural gas liquids sales and limit the benefit of decreases in interest rates. Moreover, our derivative arrangements apply only to a portion of our production and our debt and provide only partial protection against declines in commodity prices and increases in interest rates, respectively. Such arrangements may expose us to risk of financial loss in certain circumstances. We continuously reevaluate our hedging programs in light of changes in production, market conditions, commodity price forecasts, capital spending, interest rate forecasts and debt service requirements.

We use a mix of commodity swaps and costless collars and interest rate swaps to accomplish our hedging strategy. Derivative assets and liabilities with the same counterparty, subject to contractual terms which provides for net settlement, are reported on a net basis on our consolidated balance sheets. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges. These transactions are with counterparties in the financial services industry specifically with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparties. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender s commitment under our credit facility. We believe our counterparty risk is low because of the offsetting relationship we have with each of our counterparties. See Note 4 Fair Value Measurements for further information.

The following derivative contracts were in place at September 30, 2009:

Crude Oil		Volume/Month	Price/Unit	Fair Value
Oct 2009-Dec 2009	Swap	5,200 Bbls	$74.20	$ 48,808
Oct 2009-Dec 2009	Collar	12,800 Bbls	$66.55-$71.40	(62,354)
Oct 2009-Dec 2009	Collar	10,733 Bbls(1)	$115.00-$171.50	1,414,607
Jan 2010-Dec 2010	Swap	4,250 Bbls	$72.32	(104,180)
Jan 2010-Dec 2010	Collar	9,000 Bbls	$65.28-$70.60	(627,041)
Jan 2010-Dec 2010	Collar	7,604 Bbls(1)	$110.00-$181.25	3,398,019
Jan 2011-Dec 2011	Swap	3,300 Bbls	$70.74	(257,729)
Jan 2011-Dec 2011	Collar	7,000 Bbls	$64.50-$69.50	(807,512)
Natural Gas				
Oct 2009-Dec 2009	Swap	36,000 MMbtu	$8.32	386,563
Oct 2009-Dec 2009	Collar	475,000 MMbtu	$7.90-$9.45	4,388,271
Oct 2009-Dec 2009	Collar	101,200 MMbtu(1)	$9.50-$18.70	1,417,191
Jan 2010-Jun 2010	Swap	45,833 MMbtu(1)	$6.25(2)	93,545
Jan 2010-Dec 2010	Swap	29,000 MMbtu	$7.88	585,266
Jan 2010-Dec 2010	Collar	351,000 MMbtu	$7.57-$9.05	6,666,180
Jan 2010-Dec 2010	Collar	85,167 MMbtu(1)	$9.00-$15.25	3,065,348
Jan 2011-Dec 2011	Collar	266,000 MMbtu	$7.32-$8.70	2,548,223
Interest Rate		**Notional Amount**	**Fixed LIBOR Rate**	
Oct 2009-Dec 2010	Swap	$50,000,000	1.50%	(500,319)
Oct 2009- May 2011	Swap	$150,000,000	2.90%	(4,734,104)
		Total net fair value asset of derivative instruments		$ 16,918,782

(1) Average volume per month for the remaining contract term

(2) Average price for the contract term

The total net fair value asset for derivative instruments at September 30, 2009 was approximately $16.9 million and at December 31, 2008 was approximately $34.2 million, which are shown as derivative instruments in assets and liabilities on the balance sheet.

The following table details the effect of derivative contracts on the Consolidated Statements of Operations:

Location of Gain or (Loss)	Amount of Gain or (Loss) Recognized in Income

Contract Type	Recognized in Income	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Commodity prices	Operating revenues	$ 10,368,926	$ (5,712,364)	$ 30,809,560	$ (13,230,982)
Interest rate	Interest expense	(1,158,810)	(1,304,933)	(3,242,533)	(2,783,796)
	Realized gain (loss)	$ 9,210,116	$ (7,017,298)	$ 27,567,027	$ (16,014,779)
Commodity prices	Other income (expense)	$ (9,585,588)	$ 87,380,831	$ (17,689,012)	$ 752,333
Interest rates	Other income (expense)	(344,359)	1,520,507	451,103	912,208
	Unrealized gain (loss)	$ (9,929,947)	$ 88,901,338	$ (17,237,909)	$ 1,664,541

6. DEBT

On November 6, 2009, we entered into a second and third amendment to our senior secured revolving credit facility, dated May 31, 2007, as amended (*Senior Credit Agreement*). This facility provides cash availability for acquisitions of oil and gas properties and for general corporate cash requirements. The Senior Credit Agreement provides for aggregate borrowings of up to $400.0 million, with an initial borrowing base of $200.0 million that decreased to $140.0 million, effective November 2, 2009, and is subject to semi-annual redeterminations, although our lenders may elect to make one additional redetermination between scheduled redetermination dates (and have expressly reserved the right to do so between January 1, 2010 and May 1, 2010). The next borrowing base redetermination is scheduled for January 1, 2010. These amendments to the Senior Credit Agreement provide, among other things, for (i) a change in the voting percentages required for certain amendments or waivers from 50.1% to 60%, and (ii) a waiver of the current ratio and the leverage ratio for the quarter ended September 30, 2009. The Senior Credit Agreement matures on May 8, 2011. As of September 30, 2009, we had an outstanding loan balance of $141.5 million under our Senior Credit Agreement.

Also, on November 6, 2009, we issued an unsecured promissory note in an aggregate principal amount of $10.0 million to Wells Fargo Bank, National Association, the administrative agent and a lender under our Senior Credit Agreement. This promissory note bears interest at a per annum rate equal to two-month LIBOR plus 2% and matures on January 15, 2010; provided that upon an event of default resulting from the failure to make any payment of principal or interest under the promissory note, the interest rate per annum will increase to an amount equal to the lesser of the maximum rate of interest that may be charged under applicable law and LIBOR plus 4% or, if the promissory note has been assigned to any person other than any affiliate of Wells Fargo Bank, LIBOR plus 15%. All of the proceeds of the promissory note were used to repay indebtedness outstanding under the Senior Credit Agreement. As support for the obligations owed under the promissory note, OCM GW Holdings, LLC (*Oaktree Holdings*), our majority stockholder, has deposited $10.0 million in escrow for the benefit of Wells Fargo, which may, at its option, cause the note to be assigned to Oaktree Holdings and draw on the funds held in escrow.

As consideration for Oaktree Holdings agreement to deposit $10.0 million in escrow as described above, we issued an unsecured subordinated promissory note on November 6, 2009 in an aggregate principal amount of $2.0 million to Oaktree Holdings. The indebtedness under the promissory note bears interest at a rate equal to 8.0% per annum and matures on the later of (i) November 8, 2012 and (ii) the date six months after payment in full in cash of all Obligations (as such term is defined under each of the Senior Credit Agreement and the Second Lien Credit Agreement (defined below)), and the termination of all commitments to extend credit under the Senior Credit Agreement and the Second Lien Credit Agreement. The promissory note is subordinated in right of payment to the prior payment in full in cash of all obligations under the Senior Credit Agreement and the Second Lien Credit Agreement.

On July 31, 2009, we entered into the first amendment to our Senior Credit Agreement. This amendment to the Senior Credit Agreement provides, among other things, for (i) the leverage ratio to be not greater than 2.75 to 1.00 for each fiscal quarter, (ii) the current ratio to be not less than 1.00 to 1.00 for each fiscal quarter, (iii) an increased applicable margin on LIBOR loans to between 2.75% and 3.50%, and base rate loans to between 1.50% and 2.00%, depending on the percent of the borrowing base utilized at the time of the credit extension, and (iv) an increased commitment fee on unutilized commitments to 0.50%.

On November 6, 2009, we entered into a third amendment and waiver to our second lien credit agreement dated May 8, 2007, as amended (the *Second Lien Credit Agreement*), with lenders holding a majority of the then outstanding term loans under such agreement, which included an affiliate of Oaktree Holdings. The Second Lien Credit Agreement provides for a term loan in an aggregate principal amount of $150.0 million, with a term of five years with all principal amounts, together with all accrued and unpaid interest, due and payable in full on May 8, 2012. The third

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amendment to our Second Lien Credit Agreement provided, among other things, for a waiver of the leverage ratio covenant for the quarter ended September 30, 2009.

The Senior Credit Agreement and the Second Lien Credit Agreement (the *Credit Agreements*) are secured by a lien on substantially all of our assets, as well as a security interest in the stock of our subsidiaries. The obligations under the Second Lien Credit Agreement are junior to those under the Senior Credit Agreement. Interest is payable on the Credit Agreements as borrowings mature and renew.

The Credit Agreements include usual and customary affirmative covenants for credit facilities of the respective types and sizes, as well as customary negative covenants, including, among others, limitations on liens, hedging, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, certain leases and investments outside of the ordinary course of business, as well as events of default. The Credit Agreements also contain certain financial and proved reserve covenants. See Note 10 of our 2008 Annual Report on Form 10-K for a more detailed description of our covenants under the Credit Agreements, other than those revised above. At September 30, 2009, we were in compliance with the aforementioned covenants, with the exception of the current ratio under the Senior Credit Agreement and the leverage ratio under both of the Credit Agreements. We obtained waivers of such noncompliance from our lenders under the Credit Agreements for the quarter ended September 30, 2009. However, without improvement in natural gas and crude oil prices, reduction in debt levels, improvement in production volumes and/or other measures, we may not be able to comply with certain covenants under our Credit Agreements for future quarters. We continue to pursue other public and private sources of capital which would positively affect our debt covenant ratios and we continue to work with our lenders on long term amendments to our covenants. If we are unable to comply with the covenants for future quarters, we believe that it is not probable that we would not be able to cure future covenant violations by obtaining additional capital or by obtaining waivers from our lenders to cure the defaults, although we can give no assurances that any such sources of capital will be available or that such amendments will be entered into, or on terms acceptable to us. If we were not able to comply with our covenants in the future, and we were not able to obtain waivers from our lenders to cure such defaults, our lenders would have the right to demand acceleration of payment on all amounts outstanding under our Credit Agreements.

7. STOCKHOLDERS EQUITY

In the nine months ended September 30, 2009, we issued approximately 0.6 million shares of common stock, par value $0.001 per share (*Common Stock*) subject to restricted stock awards to our employees under the performance-based Long-Term Incentive Plan (*LTIP*) for the 2008 plan year. We issued 48,586 shares of restricted stock to two members of our board of directors as compensation pursuant to the Director Compensation Plan. We also issued 6,300 shares of Common Stock in payment of dividends on Series H Preferred Stock valued at $20,370 based on the closing market price on the date the shares were issued. As a result of the vesting of 124,169 shares of restricted Common Stock, 40,713 shares of such stock were withheld by us to satisfy the employees withholding tax liability, as provided for in the restricted stock agreements, with the remaining shares being released to the associated employees.

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	September 30, 2009		December 31, 2008	
Preferred Stock				
Series G, par value $0.01; 81,000 shares authorized; 80,500 shares issued and outstanding at September 30, 2009 and December 31, 2008, respectively	$	805	$	805
Series H, par value $0.01; 6,500 shares authorized; 2,100 shares issued and outstanding at September 30, 2009 and December 31, 2008, respectively		21		21
	$	826	$	826
Common Stock				
Par value $0.001; 200,000,000 shares authorized; 6,421,564 and 5,787,287 shares issued and outstanding net of treasury shares at September 30, 2009 and December 31, 2008, respectively	$	6,483	$	5,808
Treasury Stock				
At cost, 61,338 and 20,625 shares at September 30, 2009 and December 31, 2008, respectively	$	(383,705)	$	(250,594)

The following table sets forth the accumulated value of undeclared dividends on our preferred stock at September 30, 2009 and December 31, 2008, respectively:

	September 30, 2009		December 31, 2008	
Series G Preferred Stock	$	17,679,445	$	14,365,860
Series H Preferred Stock		6,790		9,380
	$	17,706,235	$	14,375,240

Until such time as the Board of Directors declares and pays dividends on our Series G Preferred Stock, dividends shall continue to accumulate. Dividends on our Series H Preferred Stock are declared quarterly by our Board of Directors, and are paid out in Common Stock the following quarter.

8. SHARE-BASED COMPENSATION

We have share-based compensation for employees and directors, which includes both stock option and restricted stock awards. The following table reflects share-based compensation expense, assuming a 35.0% effective tax rate for the periods ended:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008

Share-based compensation expense, net of tax of $121,594 and $507,701, and $654,290 and $1,513,904, respectively	$ 225,817	$ 942,874	$ 1,215,110	$ 2,811,537
Basic earnings per share impact	$ (0.04)	$ (0.18)	$ (0.19)	$ (0.54)
Diluted earnings per share impact	$ (0.04)	$ (0.09)	$ (0.19)	$ (0.27)

In the nine months ended September 30, 2009, we awarded approximately 0.6 million shares of restricted Common Stock and 0.5 million shares in stock options to our employees under our LTIP for the 2008 plan year. We also issued 48,586 shares of restricted Common Stock to two members of our board of directors as compensation pursuant to the Director Compensation Plan.

In the nine months ended September 30, 2008, we issued 1,538 shares of restricted Common Stock to two members of our board of directors as compensation pursuant to the Director

Compensation Plan. We also issued 533,350 shares of unvested Common Stock pursuant to restricted stock awards in exchange for the forfeiture of 1,066,700 substantially vested stock option grants. The fair value of the unvested Common Stock was calculated as $4.9 million on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was $4.3 million immediately prior to the forfeiture. The sum of the incremental value of the new award over the forfeited options, $0.6 million, and the unrecognized compensation cost for the original award as of the exchange date, $1.4 million, are being amortized using the straight line method over the new vesting period of five years, or approximately $32,000 a month.

9. INCOME TAXES

Income tax benefit for the nine months ended September 30, 2009 was $9.1 million, compared to income tax expense of $15.1 million for the nine months ended September 30, 2008. The income tax benefit for the nine months ended September 30, 2009 was based on our estimate of the effective tax rate expected to be applicable for the full year. The effective tax rate and the federal statutory rate were 35% for the nine months ended September 30, 2009.

10. RECENT ACCOUNTING PRONOUNCEMENTS

SEC 33-8995/34-59192. In December 2008, the SEC adopted Release No. 33-8995/34-59192, Modernization of Oil and Gas Reporting (*SEC 33-8995*). This release amends the oil and gas reporting disclosures that exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934 to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. The new rules include changes for pricing used to estimate reserves; permitting disclosure of possible and probable reserves; ability to include non-traditional resources in reserves and the use of new technology for determining reserves. SEC 33-8995 is effective for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. We are currently evaluating the provisions of SEC 33-8995 and assessing the impact it may have on our financial reporting disclosures.

11. SUBSEQUENT EVENTS

On November 6, 2009, we completed the second and third amendments to our Senior Credit Agreement, which changed the voting requirements for certain amendments or waivers and waived certain covenants for the quarter ended September 30, 2009. We also issued a $10.0 million promissory note with Wells Fargo Bank and a $2.0 million subordinated promissory note with Oaktree Holdings.

On November 6, 2009, we completed the third amendment to our Second Lien Credit Agreement, which waived the leverage ratio for the quarter ended September 30, 2009.

For a complete description of these events, see Note 6 Debt .

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, 2009

Barclays Capital

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. ***Other Expenses of Issuance and Distribution.***

The following table sets forth the costs and expenses, other than underwriting discounts and commissions, payable by Crimson Exploration in connection with the issuance and distribution of the securities being registered. All amounts are estimates except the SEC registration and The NASDAQ Global Market filing fees.

SEC registration fee	$	5,580
The NASDAQ Global Market filing fee		5,000
FINRA filing fee		10,500
Listing fee		
Transfer agent s fee		
Printing and engraving expenses		
Legal and accounting fees and expenses		
Miscellaneous		
Total	$	

Item 14: ***Indemnification of Directors and Officers.***

Section 145 of the Delaware General Corporation Law permits the Registrant to indemnify directors, officers, employees or agents, or persons serving in such capacity at the Registrant s request at another entity, against expenses (including attorneys fees), judgments, fines and amounts paid in settlement actually and reasonably incurred, other than an action by or in the right of the Registrant, to which such director, officer, employee or agent may be a party, provided such person shall have acted in good faith and shall have reasonably believed that his conduct was in or not opposed to the best interests of the Registrant and, in the case of a criminal proceeding, that he had no reasonable cause to believe his conduct was unlawful. In connection with an action by or in the right of the Registrant against a director, officer, employee or agent, the Registrant has the power to indemnify such director, officer, employee or agent for actual and reasonable expenses (including attorneys fees) incurred in connection with the defense or settlement of such suit (a) if such person acted in good faith and in a manner he reasonably believed to be in or not opposed to the best interest of the Registrant, and (b) if found liable to the Registrant, only if ordered by a court of law. Section 145 provides that such section is not exclusive of any other indemnification rights granted by the Registrant to directors, officers, employees or agents. The Delaware General Corporation Law provides for mandatory indemnification of directors and officers where such director or officer is successful on the merits in the types of proceedings discussed above.

The Certificate of Incorporation and Bylaws of the Registrant provides for mandatory indemnification of directors to the fullest extent authorized or permitted by applicable law. The right to indemnification is a contract right and includes the right to be paid by the Registrant the expenses incurred in defending any such proceeding in advance of its final disposition. Our Bylaws provide that, if the Delaware General Corporation Law requires, an advancement of expenses incurred by a director in his capacity as a director or officer of the Registrant may be made only upon delivery to the Registrant of an undertaking to repay all advanced amounts if it is ultimately determined by final nonappealable judicial decision that such person is not entitled to be indemnified for those expenses.

The Certificate of Incorporation of the Registrant also contains a provision eliminating the liability of a director to the Registrant or its stockholders for monetary damages for breach of fiduciary duty as a director, except to the extent such exemption from liability or limitation thereof is not permitted by the Delaware General Corporation Law.

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The Registrant has obtained insurance on behalf of the Registrant and its directors and officers individually against certain liabilities. By reason of this coverage, the Registrant and its directors and officers will be insured against most lawsuits and claims arising from unintentional acts or omissions, including such lawsuits and claims brought under the federal securities laws (other than under Section 16(b) of the Exchange Act). In addition, our directors and officers have entered into indemnification agreements providing for indemnification and advancement of expenses in connection with legal proceedings.

Item 15. ***Recent Sales of Unregistered Securities.***

As shown in the table below, since January 1, 2006, we issued common stock not registered under the Securities Act of 1933, as amended, in transactions we believe are exempt under Section 4(2) of the Act due to the limited number of persons involved and their relationship with us or in the case of conversions, exempt under Section 3(a)(9) of the Act. No underwriters were used, and no underwriting discounts or commissions were paid in connection with the sales.

Date	Derivative	Holder(s)	Underlying Shares	Exercise/ Conversion Price	Consideration
7/11/2008	Common Stock	Existing Stockholders	14,286	$ 9.00	Series H Preferred Stock Conversion
2/7/2008	Common Stock	Existing Stockholder	34,821	$ 9.00	Series G Preferred Stock Conversion
12/20/2007	Common Stock	Existing Stockholder	50,000	$ 80.00	Series D Preferred Stock Conversion
10/05/2007	Common Stock	Accredited Investors	2,818	NA	Director Compensation
9/28/2007	Common Stock	Accredited Investors	250,000	NA	Compensation to Company s Executive Officers
5/29/2007	Common Stock	Existing Stockholder	428,572	$ 3.50	Series H Preferred Stock Conversion
5/29/2007	Common Stock	Existing Stockholder	291,247	$ 9.00	Series E Preferred Stock Conversion
5/8/2007	Common Stock	Accredited Investor	750,000	NA	EXCO Acquisition
5/12/2006	Common Stock	Accredited Investors	2,410	NA	Director Compensation
3/01/2006	Common Stock	Accredited Investors	26,234	NA	Bonus compensation to Company s Executive Officers

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Item 16. ***Exhibits and Financial Statement Schedules.***

(a) *Exhibits*

Number	Description
**1.1	Form of Underwriting Agreement
2.1	Agreement and Plan of Merger, dated March 14, 2006, among Crimson Exploration, Inc., Exploration Operating, Inc., Core Natural Resources, Inc. and its stockholders (incorporated by reference to Exhibit 2.1 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005)
2.2	Membership Interest Purchase and Sale Agreement, dated May 8, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC, Crimson Exploration Inc. and Crimson Exploration Operating Inc. (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed May 15, 2007)
2.3	Purchase and Sale Agreement, dated April 28, 2008, by and among Smith Production, Inc. and Crimson Exploration Inc. (incorporated by reference to Exhibit 2.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2008)
3.1	Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.2 to the Company s Current Report on Form 8-K filed July 5, 2005)
3.2	Certificate of Designation, Preferences and Rights of Series D Preferred Stock (incorporated by reference to Exhibit 3.3 to the Company s Current Report on Form 8-K filed July 5, 2005)
3.3	Certificate of Designation, Preferences and Rights of Series E Cumulative Convertible Preferred Stock (incorporated by reference to Exhibit 3.4 to the Company s Current Report on Form 8-K filed July 5, 2005)
3.4	Certificate of Designation, Preferences and Rights of Series G Convertible Preferred Stock (incorporated by reference to Exhibit 3.5 to the Company s Current Report on Form 8-K filed July 5, 2005)
3.5	Certificate of Designation, Preferences and Rights of Series H Convertible Preferred Stock (incorporated by reference to Exhibit 3.6 to the Company s Current Report on Form 8-K filed July 5, 2005)
3.6	Bylaws of the Crimson Exploration Inc. (incorporated by reference to Exhibit 3.7 to the Company s Current Report on Form 8-K filed July 5, 2005)
3.7	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Appendix A to the Company s Definitive Information Statement on Schedule 14C filed August 18, 2006)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 3.7 to the Company s Current Report on Form 8-K filed July 5, 2005)
4.2	Letter Agreement by and among GulfWest Energy Inc., a Texas corporation, GulfWest Oil & Gas Company and the investors listed on the signature page thereof, dated April 22, 2004 (incorporated by reference to Exhibit 4.2 to the Company s Current Report on Form 8-K filed on May 10, 2004)
4.3	Registration Rights Agreement, dated May 8, 2007, by and between Crimson Exploration Inc. and EXCO Resources, Inc. (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed May 15, 2007)
4.4	Shareholders Rights Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(e) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
4.5	Omnibus and Release Agreement among GulfWest Energy Inc., OCM GW Holdings, LLC and those signatories set forth on the signature page thereto, dated as of February 28, 2005 (incorporated by

	reference to Exhibit 99(f) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
**5.1	Opinion of Akin Gump Strauss Hauer & Feld LLP
#10.1	Amended and Restated Employment Agreement between Allan D. Keel and Crimson Exploration Inc., dated December 30, 2008 (incorporated by reference to Exhibit 10.1 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008)

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Number	Description
#10.2	Amended and Restated Employment Agreement between E. Joseph Grady and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.2 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.3	GulfWest Oil Company 1994 Stock Option and Compensation Plan, amended and restated as of April 1, 2001 and approved by the stockholders on May 18, 2001 (incorporated by reference to Exhibit I of the Company s Proxy Statement on Form DEF 14A, filed on April 16, 2001)
#10.4	GulfWest Energy Inc. 2004 Stock Option Incentive Plan. (incorporated by reference to Exhibit 10.4 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2004)
#10.5	GulfWest Energy Inc. 2005 Stock Option Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2004)
#10.6	Form of GulfWest Energy Inc. 2005 Stock Incentive Plan Stock Option Agreement (incorporated by reference to Exhibit 10.6 of Amendment No. 1 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2005)
#10.7	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on July 21, 2005)
10.8	Series G Subscription Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(a) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
10.9	Series A Subscription Agreement between GulfWest Oil & Gas Company and OCW GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(b) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
10.10	Oil and Gas Property Acquisition, Exploration and Development Agreement with Summit Investment Group-Texas, L.L.C. effective December 1, 2001 (incorporated by reference to Exhibit 10.8 to the Company s Registration Statement No. 333-116048 on Form S-1)
#10.11	Amended and Restated Employment Agreement between Tracy Price and Crimson Exploration Inc., dated December 30, 2008 (incorporated by reference to Exhibit 10.11 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2009)
#10.12	Amended and Restated Employment Agreement between Tommy Atkins and Crimson Exploration Inc., dated December 29, 2008 (incorporated by reference to Exhibit 10.12 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.13	Amended and Restated Employment Agreement between Jay S. Mengle and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.13 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.14	Summary terms of Director Compensation Plan (incorporated by reference to Exhibit 10.14 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.15	Form of director and officer restricted stock grant (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on July 21, 2005)
10.16	Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed May 15, 2007)
#10.17	Form of executive officer restricted stock grant for grants outside the 2005 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company s Current Report on Form 8-K filed August 7, 2007)
10.18	Amendment No. 1, dated as of June 5, 2007, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on

Form 8-K filed June 8, 2007)

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Number	Description
10.19	Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., as borrower, Wells Fargo Bank, National Association, as agent, Wells Fargo Bank, National Association and The Royal Bank of Scotland, plc, as co-lead arrangers and joint bookrunners, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed June 6, 2007)
#10.20	Employment Agreement between Rusty Shepherd and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.20 to the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.21	Crimson Exploration Inc. 2005 Stock Incentive Plan, Amended and Restated Effective as of August 15, 2008 (incorporated by reference to Exhibit A of the Company s Information Statement on Schedule 14C filed September 25, 2008)
#10.22	Form of Restricted Stock Award used in connection with option exchange and in connection with the Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company s Current Report on Form 8-K filed September 11, 2008)
#10.23	Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.24	Cash Incentive Bonus Plan (incorporated by reference to Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.25	Long Term Performance Plan Form of Restricted Stock Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.26	Long Term Incentive Performance Plan Form of Stock Option Agreement for Employees (incorporated by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.27	Long Term Incentive Performance Plan Form of Restricted Stock Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.28	Long Term Incentive Performance Plan Form of Restricted Stock Option Agreement for Executive Officers (incorporated by reference to Exhibit 10.4 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.29	Amendment No. 2, dated as of May 13, 2009, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.5 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.30	Amendment No. 3 and Waiver, dated as of November 6, 2009, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., Crimson Exploration Operating, Inc. and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K for the quarter filed November 13, 2009)
10.31	First Amendment, dated as of July 31, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, by and among Crimson Exploration Inc., the guarantor party thereto, the lenders party thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed August 5, 2009)
10.32	Second Amendment, dated as of November 6, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lenders party thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed November 13, 2009)

10.33 Third Amendment and Limited Waiver, dated as of November 6, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lenders party thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed November 13, 2009)

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Number	Description
10.34	Promissory Note, dated November 6, 2009, made by Crimson Exploration Inc. to Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed November 13, 2009)
10.35	Subordinated Promissory Note, dated November 6, 2009, made by Crimson Exploration Inc. to OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed November 13, 2009)
*21.1	Subsidiaries of the Registrant
*23.1	Consent of Grant Thornton LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
**23.3	Consent of Akin Gump Strauss Hauer & Feld LLP (contained in Exhibit 5.1)
24.1	Power of Attorney (included on signature page of this Registration Statement)

* Filed herewith

** To be filed by amendment.

\# Management contract or compensatory plan or arrangement

(b) *Financial Statement Schedules*

No financial statement schedules are included herein. All other schedules for which provision is made in the applicable accounting regulation of the SEC are not required under the related instructions, are inapplicable, or the information is included in the consolidated financial statements, and have therefore been omitted.

Item 17. ***Undertakings.***

The undersigned Registrant hereby undertakes the following:

(1) Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the Registrant pursuant to the foregoing provisions, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

(2) (a) For purpose of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in the form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective; and

(b) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on the 20th day of November, 2009.

Crimson Exploration Inc.

By: /s/ Allan D. Keel

Allan D. Keel
President and Chief Executive Officer

POWER OF ATTORNEY

Each of the undersigned directors and officers of Crimson Exploration Inc. hereby constitutes and appoints Allan D. Keel and E. Joseph Grady, and each of them, his true and lawful attorneys-in-fact and agents with full power of substitution and resubstitution, for him and his name place and stead, in any and all capacities, to execute any and all amendments (including post-effective amendments) to this registration statement, to sign any registration statement filed pursuant to Rule 424(b) of the Securities Act of 1933, and to cause the same to be filed with all exhibits thereto, and all documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and desirable to be done in and about the premises as fully and to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all acts and things that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed below by the following persons in the capacities and on the dates indicated below.

Signature	Title	Date
/s/ Allan D. Keel Allan D. Keel	President, Chief Executive Officer and Director (Principal Executive Officer)	November 20, 2009
/s/ E. Joseph Grady E. Joseph Grady	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	November 20, 2009
/s/ Terence Lynch Terence Lynch	Chief Accounting Officer (Principal Accounting Officer)	November 20, 2009
/s/ B. James Ford B. James Ford	Director	November 20, 2009

/s/ Adam C. Pierce	Director	November 20, 2009
Adam C. Pierce		
/s/ Lee B. Backsen	Director	November 20, 2009
Lee B. Backsen		
/s/ Lon McCain	Director	November 20, 2009
Lon McCain		

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