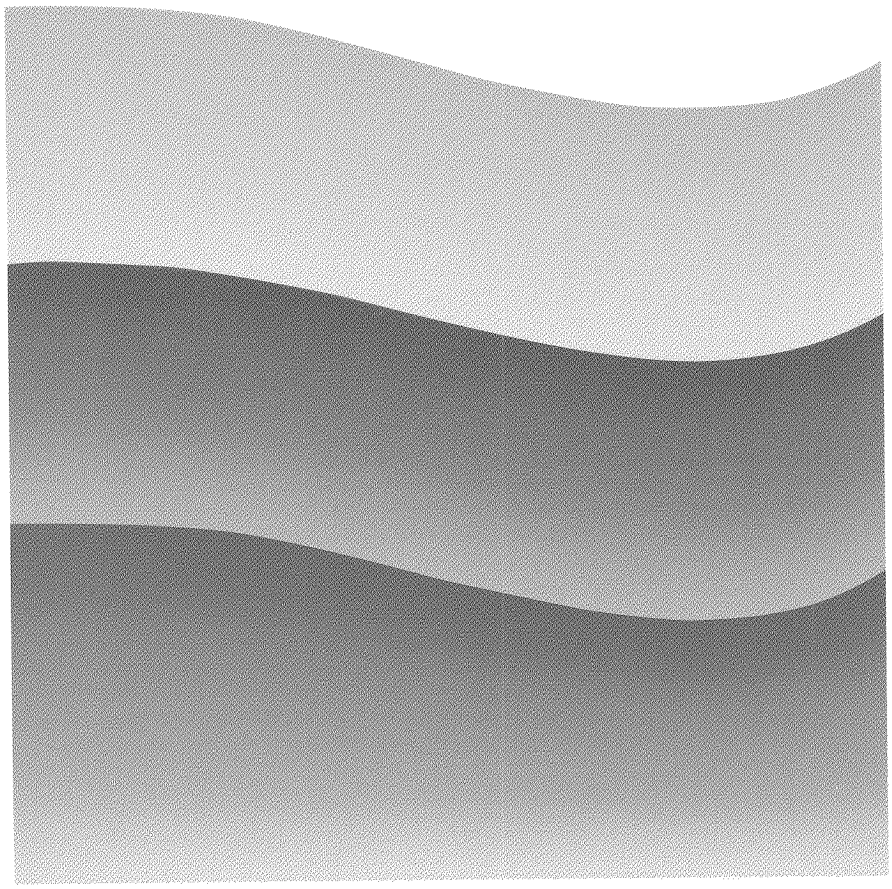


SANDRIDGE ENERGY, INC.

2009 ANNUAL REPORT

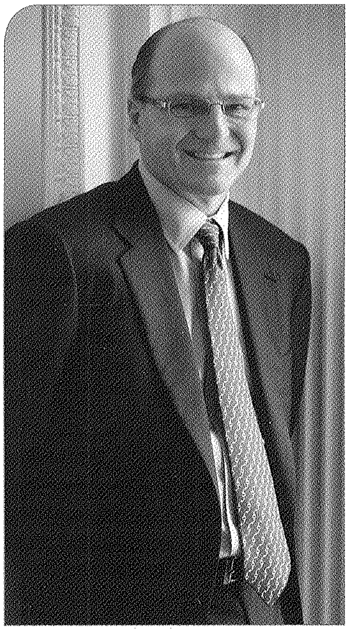
SandRidge

Agave Americana, commonly known as the Century Plant, is an agave originally from Mexico, but cultivated worldwide as an ornamental plant. The Century Plant is found throughout the West Texas Overthrust.

Sunrise at the Century Plant — Fort Stockton, Texas.

SandRidge Energy, Inc. is an independent exploration and production company, with focused activities in proven oil and natural gas basins, primarily in the Permian Basin and West Texas Overthrust regions. SandRidge holds a unique place in the industry as one of the few companies today that pursues low cost, low risk traditional reserves. While most of the industry has moved toward shale plays and horizontal drilling, we drill predominantly vertical wells into reservoirs with long-lived reserve decline curves.

Growth through a balanced focus on oil and natural gas is key to enhancing the long-term value of our company. Recent acquisitions in the Permian Basin and the 2010 opening of the Century Plant – the largest single industrial source CO_2 capture facility in North America – further our mission of long-term value creation.



Tom L. Ward
Chairman and CEO

FELLOW SHAREHOLDERS,

TWO-THOUSAND AND NINE WAS A YEAR OF TRANSFORMATION FOR SANDRIDGE ENERGY AS WE TOOK STEPS TO BALANCE OUR PORTFOLIO OF ASSETS.

SandRidge today is a company whose oil reserves comprise over 50 percent of its total PV-10 value basis. Even as natural gas prices remained low in 2009, oil prices recovered to an attractive level and currently provide a much higher return on invested capital. Although we remain positive about the future, we suspect that near-term pricing of natural gas could face significant challenges.

> "EVEN AS NATURAL GAS PRICES REMAINED LOW IN 2009, OIL PRICES RECOVERED TO AN ATTRACTIVE LEVEL AND CURRENTLY PROVIDE A MUCH HIGHER RETURN ON INVESTED CAPITAL."

Our management team has focused SandRidge on natural gas and worked to increase our production – from 20 million cubic feet of gas equivalent per day (Mmcfe/d) in June 2006 to 325 Mmcfe/d at year-end 2008. However, as commodity prices dropped sharply in the latter half of 2008 in reaction to the severe decline in U.S. and world economies, we knew we would have to modify our strategies.

The first step was to slow our drilling program. We moved from a planned $2 billion budget for 2009, to $500 million in drilling, and went from a high of 47 active rigs in August 2008 to a low of just four rigs running in early 2009. This enabled us to cut our capital expenditures (CAPEX) without dramatically affecting our earnings before interest, taxes, depreciation and amortization (EBITDA) thanks to the effectiveness of our hedging program, which locked in our natural gas prices through 2010. Next, we moved to diversify the company and in late 2009 successfully completed an $800 million acquisition of Permian Basin oil properties.

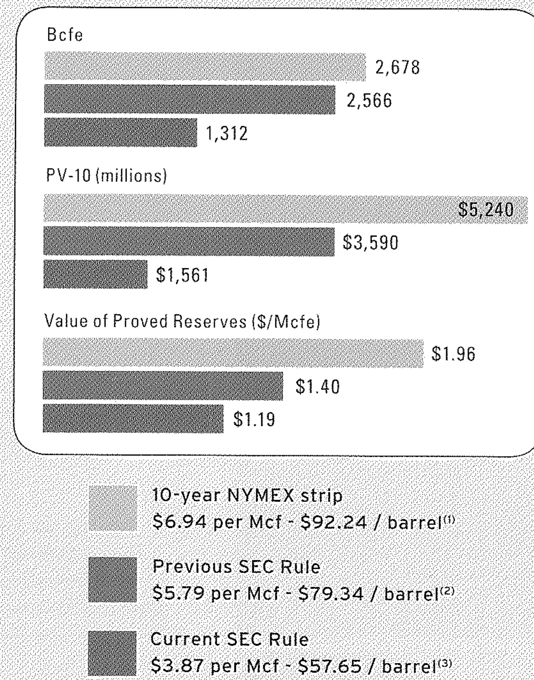
PROVED RESERVES AND THE VALUE OF OIL

One of the key measures oil and natural gas producers report each year is the amount of their proved reserves – the amount of oil and natural gas that can be produced in future years with reasonable certainty. These amounts are based, in part, on existing economic conditions – the price at which each of these products can be sold. In order to ensure all companies use the same metrics to calculate their reserves, the Securities and Exchange Commission (SEC) provides specific requirements that must be followed when calculating proved reserves.

In past years, the SEC required that the year-end NYMEX spot price be used when calculating proved reserves. Using this scenario the reference price for 2009 year-end reserves would have been $5.79 per Mcf of natural gas and $79.34 per barrel of oil. In 2009, however, the SEC changed the requirement to a 12-month average of the spot price on the first day of each month, resulting in a 2009 reference price of $3.87 per Mcf of natural gas and $57.65 per barrel of oil. As illustrated by the chart on the right, the reference price used makes an enormous difference in the quantity of proved reserves that can be reported.

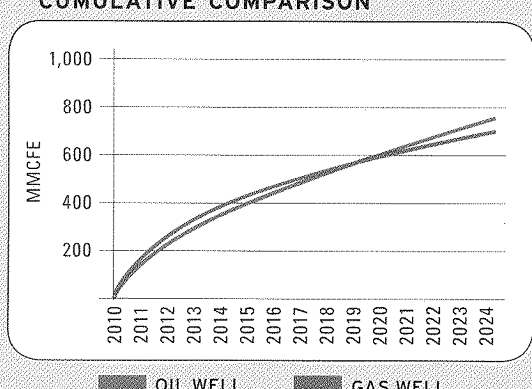
What is often overlooked when reviewing reserve numbers is the mix of oil and natural gas within those reserves and the value presented by each. Reserves are calculated according to the standard SEC comparison of 6 Mcf of natural gas to 1 barrel of oil (6:1). However, as the prices of the two commodities have diverged, the real economic ratio equals a range of 13:1 to 16:1, giving oil reserves approximately double the value that is factored into the reserve number alone. As illustrated by the charts below, when comparing a natural gas well with an oil well with similar reserves, production and capital expenditures, the oil well provides a much higher rate of return than the natural gas well in the current pricing environment. With our current mix of oil and natural gas locations, SandRidge has the option to adjust from natural gas to oil drilling and back again as dictated by project economics and return on investment.

PROVED RESERVES

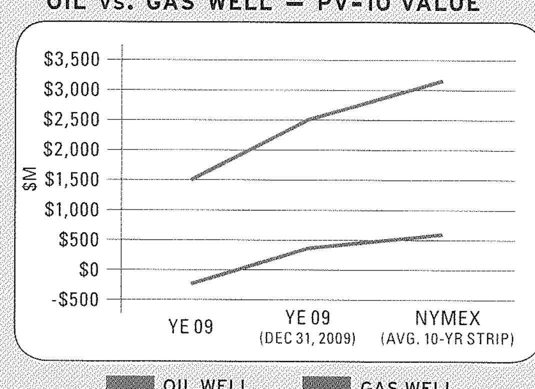


(1) Constant price based upon the average 10-year NYMEX strip as of December 31, 2009
(2) Spot prices at December 31, 2009
(3) 12-month average prices under current SEC rules. Oil is West Texas Intermediate posted price, NYMEX equivalent price of $61.14

CUMULATIVE COMPARISON



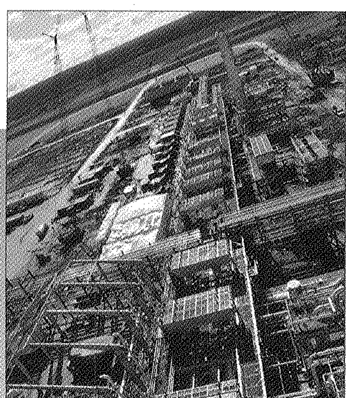
OIL VS. GAS WELL – PV-10 VALUE



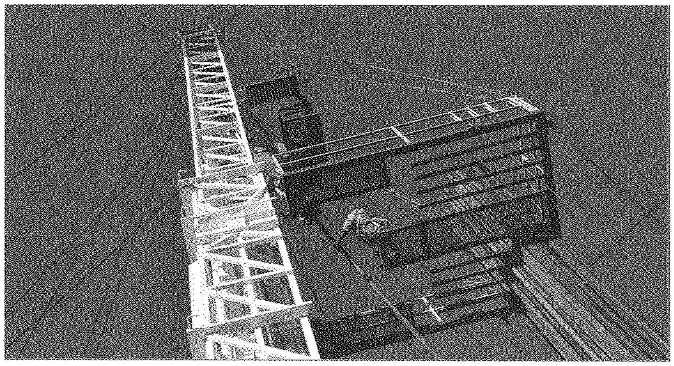
THE CASE FOR OIL The charts above compare a natural gas well and an oil well, each with reserves of approximately .77 Bcfe, $950 million of capital expenditures assigned to them, and similar production profiles (left). The oil well, however, provides a much higher rate of return than the natural gas well in today's pricing environment (right).

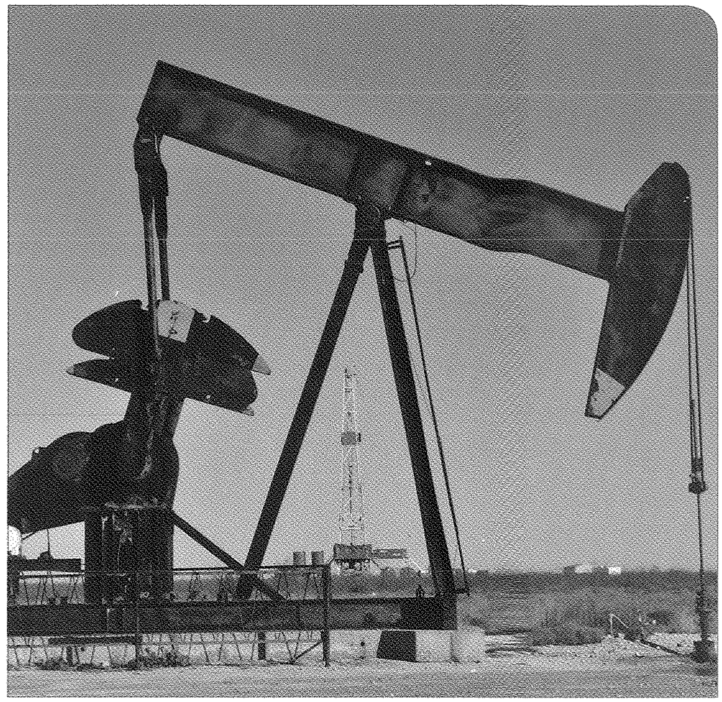
TOP A view of the absorber tower at the Century Plant in Fort Stockton, Texas.
BOTTOM Looking southeast, from above the construction of Phase One of the Century Plant.

The Clear Fork and San Andres are both proven formations, and currently generate the company's highest returns on invested capital.

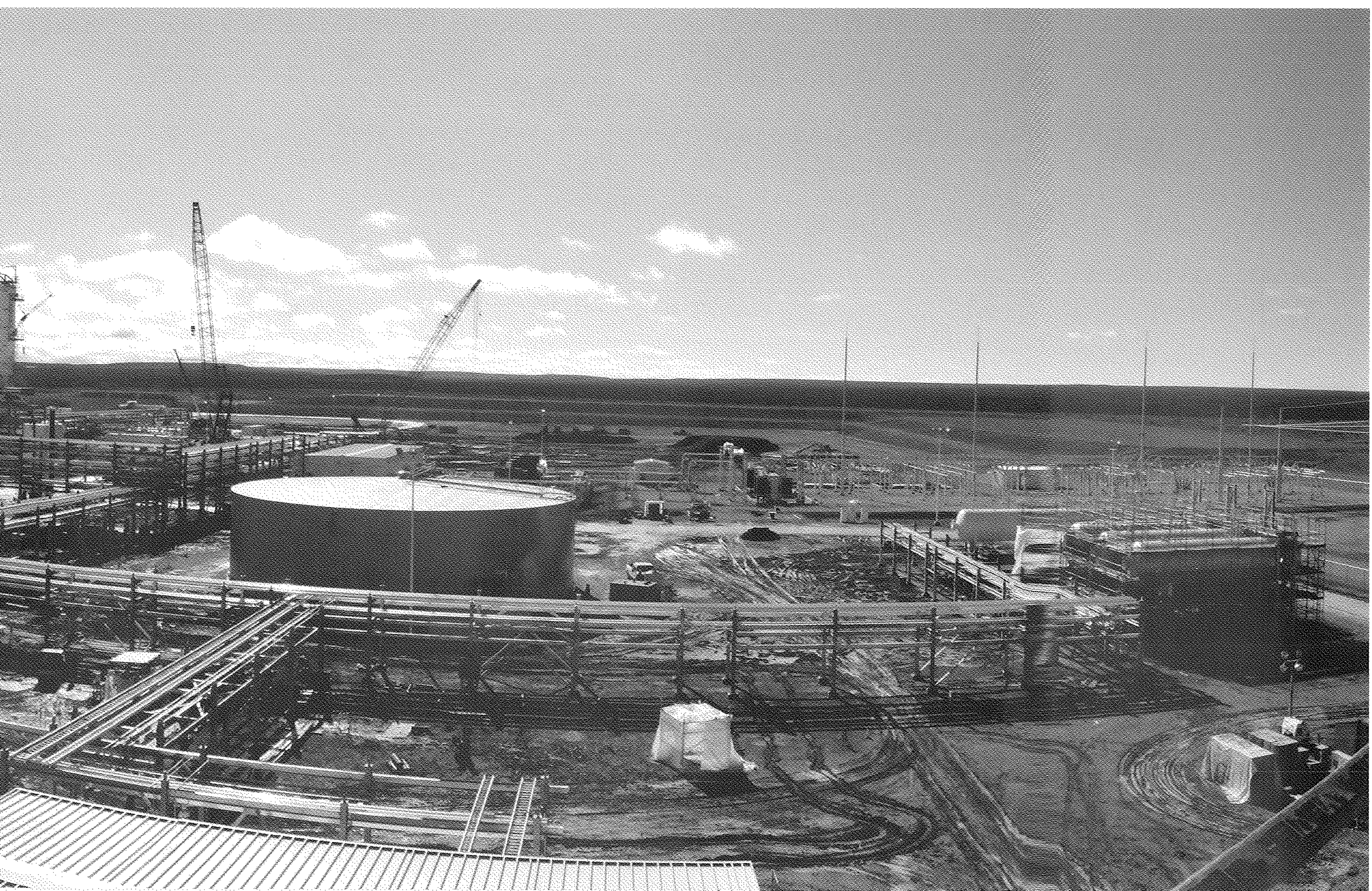


In 2009, SandRidge acquired 80 MMboe (482 Bcfe) of proved oil reserves and more than 90 MMboe (540 Bcfe) of resource potential in the Central Basin Platform of the Permian Basin.

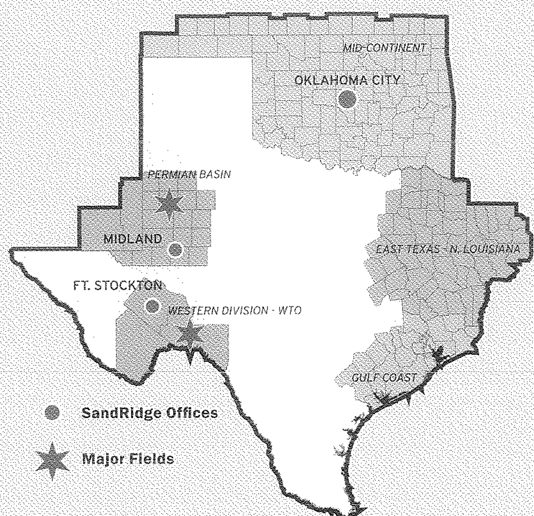




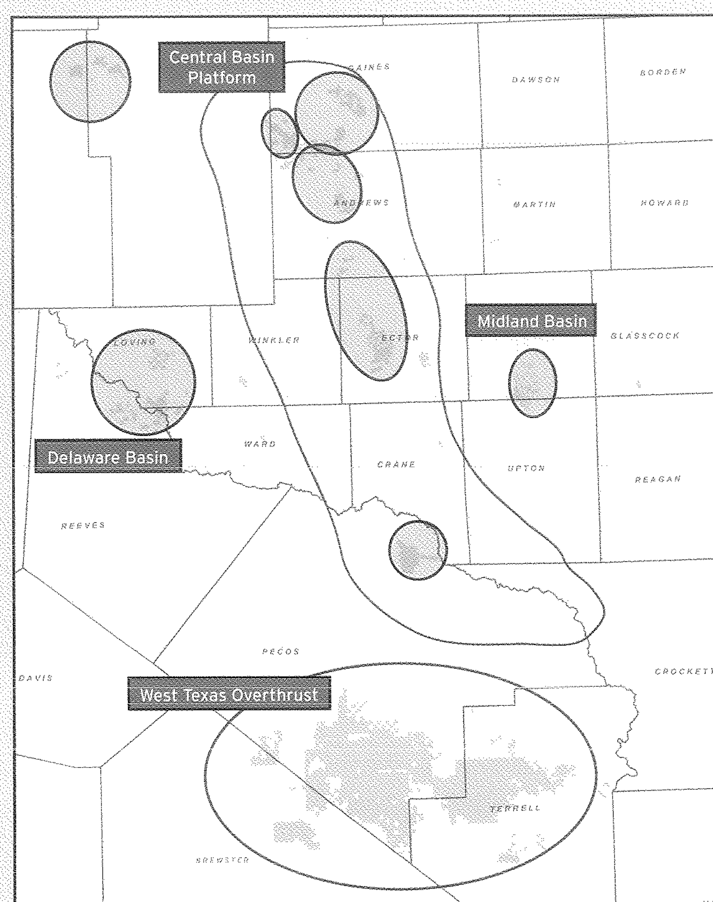
Panoramic view of the Century Plant, currently under construction in Fort Stockton, Texas.



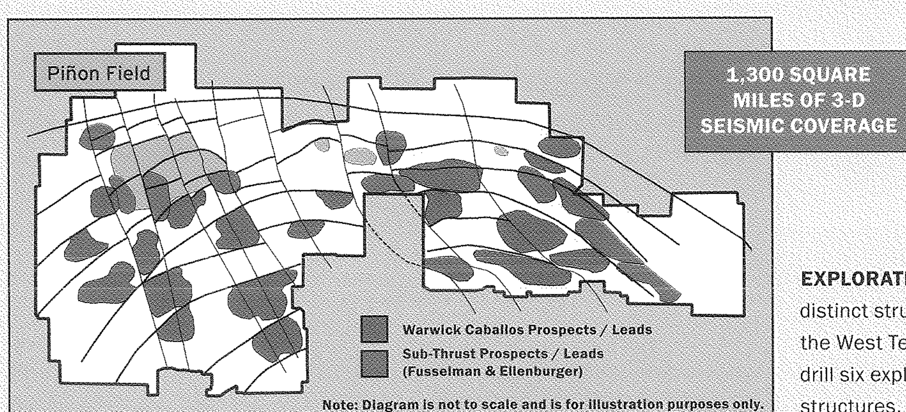
CORE AREAS OF OPERATION



CORE AREAS SandRidge focuses its exploration and production activities in the Permian Basin, the West Texas Overthrust, the Mid-Continent, the Cotton Valley Trend in East Texas, the Gulf Coast and the Gulf of Mexico.



PERMIAN BASIN AND WEST TEXAS OVERTHRUST SandRidge is poised to grow through development of Permian Basin oil properties and natural gas properties in the West Texas Overthrust. We maximize earnings by running an appropriate mix of rigs in oil and natural gas plays and have the option to further adjust as necessary.



EXPLORATION SandRidge has found leads to 20 distinct structures to potentially explore within the West Texas Overthrust. In 2010, we plan to drill six exploratory wells, testing several separate structures.

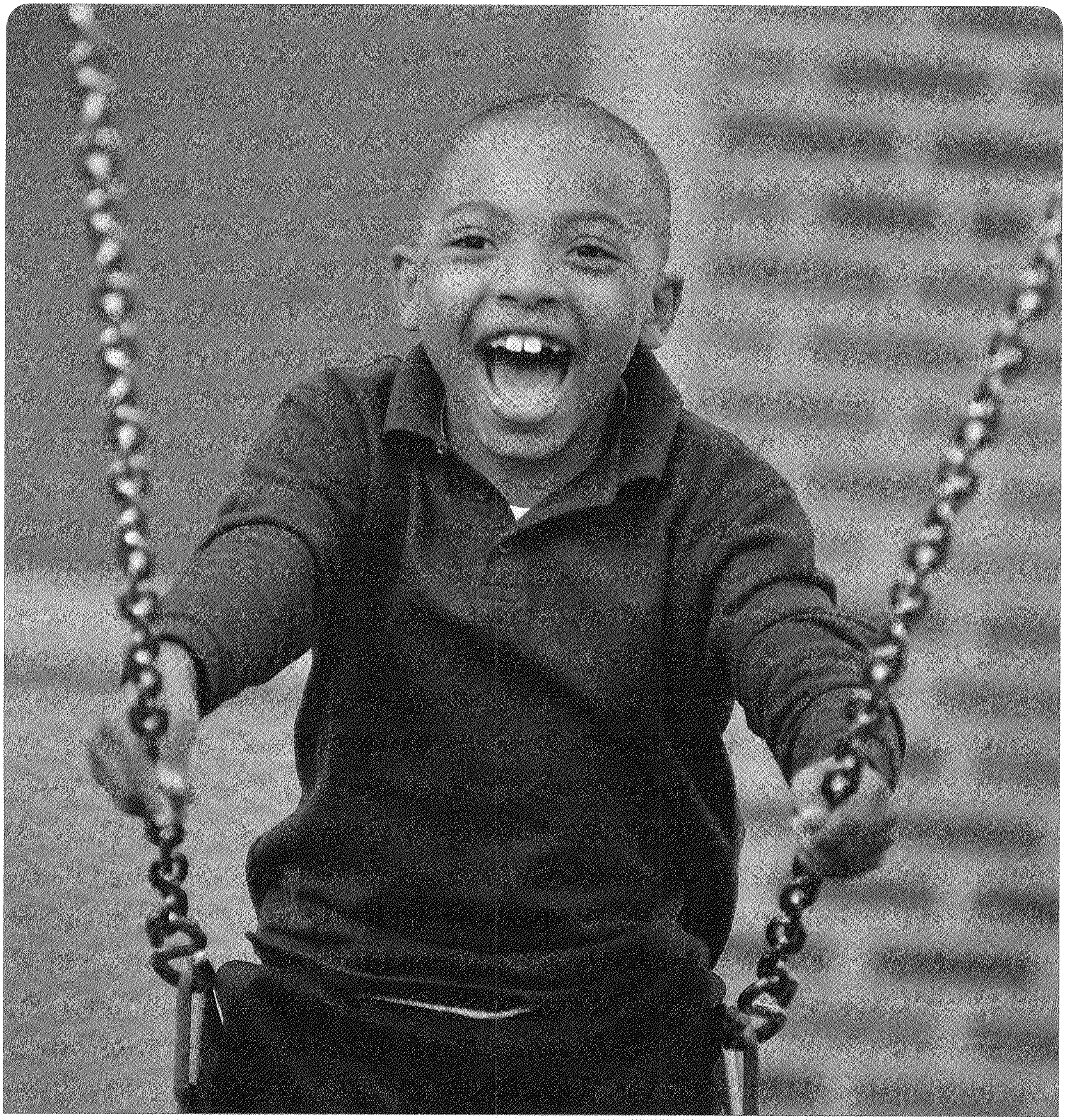
Oil Rig - Permian Basin.

> "WE ARE PARTICULARLY EXCITED ABOUT THE OPPORTUNITIES WE NOW HAVE IN THE CENTRAL BASIN PLATFORM WHERE WE ARE EXPANDING OUR SUCCESSFUL CLEAR FORK AND SAN ANDRES DRILLING PROGRAMS. THANKS TO ATTRACTIVE OIL PRICES AND LOW DRILLING COSTS, THE CLEAR FORK AND SAN ANDRES CURRENTLY GENERATE THE COMPANY'S HIGHEST RETURNS ON INVESTED CAPITAL."

In addition, we strengthened our balance sheet through private and public debt and equity transactions and the sale of non-core assets, raising $1.8 billion in 2009. These transactions enabled us to pay down our credit revolver, finance our CAPEX budget and fund the Permian Basin acquisition.

In 2009, we hedged 77 percent of our total production at an average price of $8.59 per thousand cubic feet of natural gas equivalent (Mcfe). In 2010, we have 80 billion cubic feet (Bcf) of natural gas hedged at an average price of $7.70 per Mcf, and 4.38 million barrels of oil (MMBbls) hedged at an average price of $82.04 per barrel. This accounts for approximately 80 percent of our expected 2010 production at an average price of $9.17 per Mcfe.

In November 2008, we broke ground on the Century Plant CO_2 treating facility located just outside of Fort Stockton, Texas. Built in partnership with Occidental Petroleum (Oxy), the Century Plant will be the largest CO_2 treating plant in the world in terms of volume of CO_2 removed and captured. Under the agreement, Oxy will pay for the construction while SandRidge will build the plant and drill the wells necessary to deliver the combined CO_2 and methane gas stream to the plant for treatment. Once separated, SandRidge will deliver the



ENERGY TO GIVE SandRidge and its employees are committed to playing a positive role in our local communities. Through our focus on child advocacy, SandRidge works to improve the health, education and well-being of children — particularly those who live in disadvantaged situations. We do so through direct financial contributions, volunteerism and fundraising efforts. Every child is special and has unique gifts to offer the world, and it is our goal to help them realize their own worth and potential.

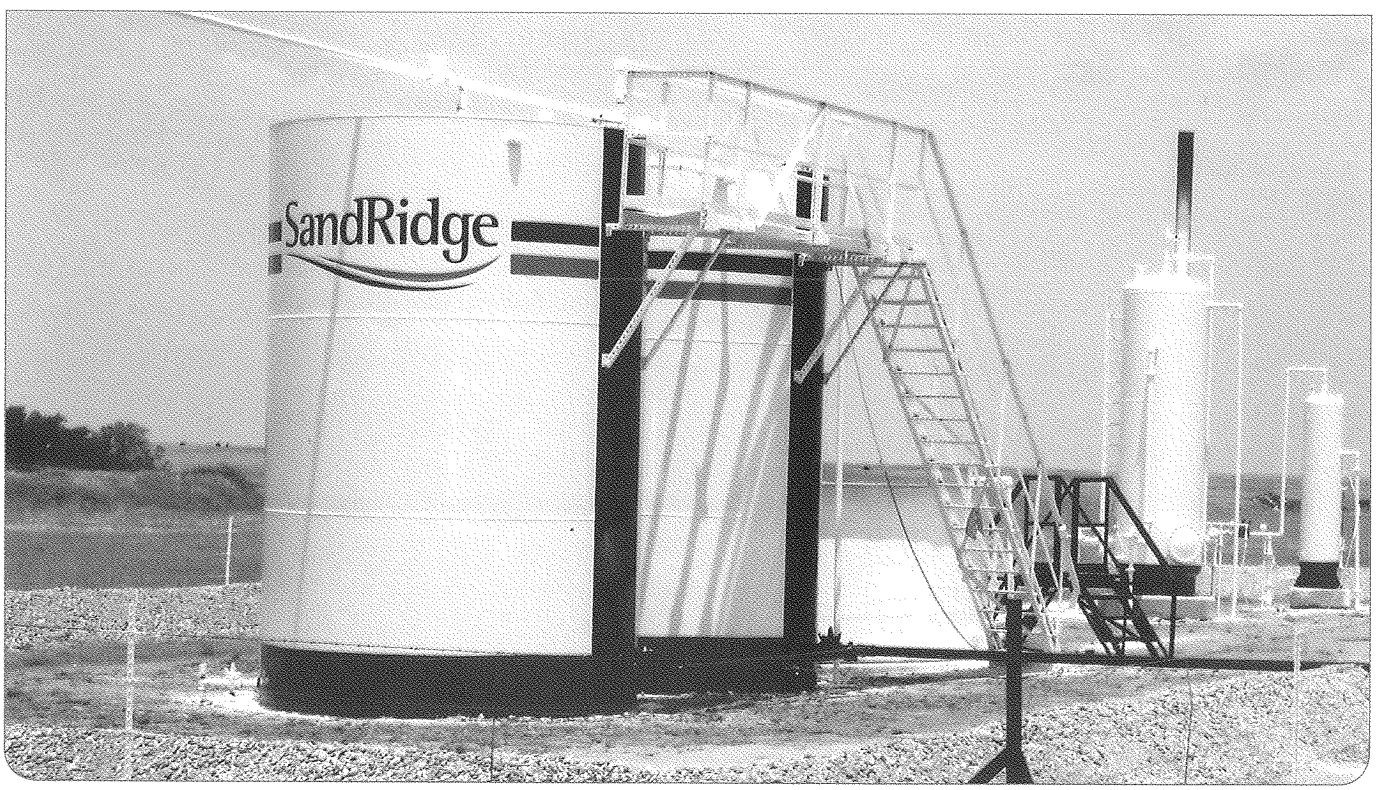
"WE ARE FORTUNATE TO BE ABLE TO MAXIMIZE EARNINGS BY RUNNING AN APPROPRIATE MIX OF RIGS IN OUR OIL AND NATURAL GAS PLAYS WHILE HAVING THE OPTION TO ADJUST FURTHER FROM NATURAL GAS TO OIL DRILLING AS DICTATED BY PROJECT ECONOMICS AND RETURN ON INVESTMENT."

methane for sale into the marketplace and Oxy will take the CO_2 to the Permian Basin for environmentally-friendly sequestration in its tertiary oil recovery projects.

The opening of the plant this summer will allow us to increase drilling in our primary target in the Piñon Field, the Warwick Thrust. The shallow decline curve inherent in the Warwick allows us to maintain our production much more easily than reservoirs with steep initial declines. Because of its high CO_2 content, however, the ability to separate the gas stream is key to our ability to access this prolific natural gas zone.

Phase II of the Century Plant, scheduled for completion in late 2011, will potentially add another 400 MMcf per day of CO_2 treating capacity, giving SandRidge a total capacity exceeding one Bcf per day of total inlet gas.

In late 2009, SandRidge acquired 80 MMboe (482 Bcfe) of proved reserves and more than 90 MMboe (540 Bcfe) of resource potential in the Central Basin Platform of the Permian Basin. This acquisition raises our leasehold position in the area to more than 150,000 acres and significantly increases our ability to develop and produce oil and natural gas from our core West Texas properties. This transaction



SandRidge tank battery.

was particularly unique because it allowed us to acquire a package of quality oil properties for an amount that will be largely recouped over the next three years by hedging the proved developed production, while also obtaining the undeveloped resource potential upside for a nominal amount.

We are particularly excited about the opportunities we now have in the Central Basin Platform where we are expanding our successful Clear Fork and San Andres drilling programs. Thanks to attractive oil prices and low drilling costs, the Clear Fork and San Andres currently generate the company's highest returns on invested capital. Both formations are proven, producing billions of barrels of oil since being discovered in the early 1900s.

Wells drilled in the San Andres reach a total depth of 4,500 feet in just four days while Clear Fork wells reach a total depth of 6,200 feet in seven days. Both reservoirs have long established decline curves for trusted economic returns.

We have reduced the commodity price risk associated with the acquisition of these properties by entering into oil hedges, which lock in over $1.3 billion of future revenue through 2012. In addition, we believe there is a tremendous amount of upside remaining in these properties.

Our exploration program is focused within our 500,000 acres of leasehold in the West Texas Overthrust, and seeks to find structures similar to the Piñon Field. In 2008, we completed the largest contiguous proprietary onshore 3-D seismic shoot in the U.S., acquiring 1,300 square miles of data. During 2009, we processed and analyzed the data collected and found leads to 20 distinct structures to potentially explore.

Fall plant life in the Piñon Field includes numerous Century Plants.

"WE NOW HAVE AN ENVIABLE BASE TO DEVELOP NATURAL GAS IN THE PIÑON FIELD, DEVELOP OIL IN THE CENTRAL BASIN PLATFORM AND EXPLORE FOR NEW NATURAL GAS FIELDS IN THE WEST TEXAS OVERTHRUST."

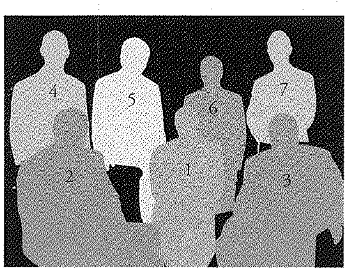
Because of the inherent risk involved in exploratory drilling, SandRidge is taking a tempered approach to testing the leads defined through our 3-D seismic analysis. In 2010, we plan to drill six exploratory wells, testing several separate structures. With just $25 million of our $860 million total CAPEX budget dedicated to exploration, and with each well having the potential of finding multiple Tcf of natural gas, we believe this to be an appropriate balance between risk and reward.

With the steps taken over the past several months, SandRidge is now poised to grow through the development of both oil and natural gas properties, and we expect the percentage of revenues from oil sales to continue to increase in the future. We now have an enviable base to develop natural gas in the Piñon Field, develop oil in the Central Basin Platform and explore for new natural gas fields in the West Texas Overthrust. We are fortunate to be able to maximize earnings by running an appropriate mix of rigs in our oil and natural gas plays while having the option to adjust further from natural gas to oil drilling as dictated by project economics and return on investment.

I would like to express my appreciation to our talented and hardworking employees for their unmatched dedication, to our board of directors for its stewardship and counsel, and finally to all of our fellow shareholders for their continued faith in the future of our company.

Tom L. Ward
Chairman and Chief Executive Officer

Century Plant pipe rack and absorber tower.



SANDRIDGE BOARD OF DIRECTORS

1 Tom L. Ward
Chairman, Chief Executive Officer & President

2 Roy T. Oliver [b,c]
President – R.T. Oliver Investments Inc.

3 Daniel W. Jordan [b,c]
Private Investor

4 D. Dwight Scott [a]
Managing Director – GSO Capital Partners

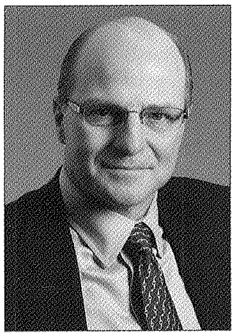
5 William A. Gilliland [b]
Managing Partner – Gillco Energy LP & Gillco Investments LP

6 Jeffrey S. Serota [a]
Senior Partner – Ares Management LLC

7 Everett R. Dobson [a]
Chairman – Dobson Technologies

a. Audit Committee
b. Compensation Committee
c. Nominating and Governance Committee

MANAGEMENT

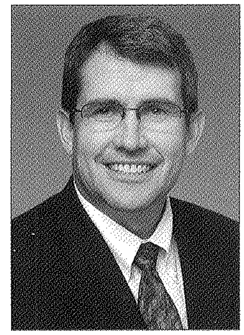


Tom L. Ward
Chairman, Chief Executive Officer and President

Dirk M. Van Doren
Executive Vice President and Chief Financial Officer

Matthew K. Grubb
Executive Vice President and Chief Operating Officer

Todd N. Tipton
Executive Vice President – Exploration

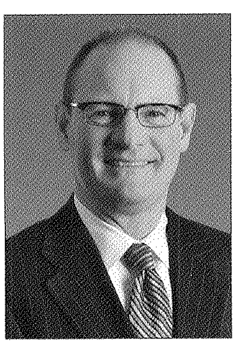


Rodney E. Johnson
Executive Vice President – Reservoir Engineering

Wayne C. Chang
Senior Vice President – Midstream

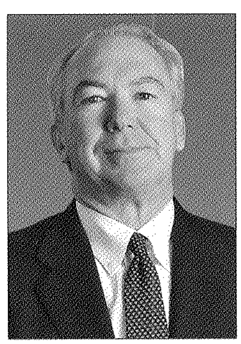
Randall D. Cooley
Senior Vice President – Accounting

Richard J. Gognat
Senior Vice President – Land and Legal, General Counsel and Corporate Secretary



Kevin R. White
Senior Vice President – Business Development

Mary L. Whitson
Senior Vice President – Human Resources



Thomas L. (Lon) Winton
Senior Vice President – Information Technology and Chief Information Officer

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

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-33784

SANDRIDGE ENERGY, INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**20-8084793** (I.R.S. Employer Identification No.)
123 Robert S. Kerr Avenue **Oklahoma City, Oklahoma** (Address of principal executive offices)	**73102** (Zip Code)

(405) 429-5500
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

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

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

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

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 ☑	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2009 was approximately $1.0 billion based on the closing price as quoted on the New York Stock Exchange. As of February 19, 2010, there were 210,413,896 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2010 Annual Meeting of Stockholders are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.

2009 ANNUAL REPORT ON FORM 10-K

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PART I

Item 1. *Business*

General

SandRidge Energy, Inc., is an independent natural gas and oil company headquartered in Oklahoma City, Oklahoma concentrating on exploration, development and production activities related to the exploitation of our significant holdings in West Texas. Our primary areas of focus are the West Texas Overthrust (the "WTO") and the Permian Basin. The WTO is a natural gas-prone geological region in Pecos County and Terrell County, Texas where we have operated since 1986 and currently have 562,626 net acres under lease. The WTO includes the Piñon gas field. In the Permian Basin, we control approximately 138,691 net acres in West Texas and New Mexico, including approximately 90,000 net acres acquired in December 2009 as further discussed below. We also operate interests in the Mid-Continent, the Cotton Valley Trend in East Texas, the Gulf Coast area and the Gulf of Mexico.

We have assembled an extensive natural gas and oil property base on which we have identified approximately 12,100 potential drilling locations as of December 31, 2009, including approximately 5,500 locations in the WTO and approximately 2,600 locations in the Permian Basin. As of December 31, 2009, our estimated proved reserves were 1,312.2 Bcfe, of which 52% were natural gas. The reports covering approximately 95% of these estimated proved reserves were prepared by third party engineers. As of December 31, 2009, we had 3,373 gross (2,721.2 net) producing wells, substantially all of which we operate, and had 1,720,909 gross (1,262,115 net) acres under lease. As of December 31, 2009, we had eight rigs drilling in the WTO, four rigs drilling in the Permian Basin, two rigs drilling in East Texas and one rig drilling in the Mid-Continent.

We also operate businesses that are complementary to our primary exploration, development and production activities which provide us with operational flexibility and an advantageous cost structure. We own related gas gathering and treating facilities, a gas marketing business and an oil field services business, including our wholly owned drilling rig business, Lariat Services, Inc. ("Lariat"). As of December 31, 2009, our drilling rig fleet consisted of 31 rigs, 30 of which were operational. We also capture and transport CO_2 to the Permian Basin.

Our principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and our telephone number is (405) 429-5500. We make available free of charge on our website at *www.sandridgeenergy.com* our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Any materials that we have filed with the SEC may be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Room 1580, Washington, D.C. 20549 or accessed via the SEC's website address at *www.sec.gov*.

References to "SandRidge," "us," "we," "Company" and "our" in this report refer to SandRidge Energy, Inc., together with its subsidiaries. "SandRidge CO_2" refers to our wholly owned subsidiary SandRidge CO_2, LLC, and "SandRidge Tertiary" refers to our wholly owned subsidiary SandRidge Tertiary, LLC.

Recent Developments

Forest Acquisition. In December 2009, we purchased natural gas and oil properties located in the Permian Basin from Forest Oil Corporation and one of its subsidiaries (collectively, "Forest") for $800.0 million, subject to purchase price and post-closing adjustments (the "Forest Acquisition"). The assets consist primarily of six operated areas in the Central Basin Platform and greater Permian Basin area of western Texas and eastern New Mexico. These properties are characterized by multiple producing horizons including the Spraberry, Wolfcamp, Grayburg, San Andres and Wichita-Albany formations. Additionally, there are significant undeveloped properties in the Clear Fork formation. Approximately 98% of the production is operated and the subject properties cover over 90,000 net acres of which nearly 80% is held by production.

Common Stock Offering. In December 2009, we completed a registered underwritten public offering of 25,600,000 shares of our common stock, including 3,600,000 shares of common stock acquired by the underwriters from us to cover over-allotments. Net proceeds from the offering were approximately $217.2 million after deducting offering expenses of approximately $9.4 million. The net proceeds were used to fund a portion of the Forest Acquisition purchase price and for general corporate purposes.

8.75% Senior Notes Due 2020. In December 2009, we completed the sale of $450.0 million of our unsecured 8.75% Senior Notes due 2020 (the "8.75% Senior Notes") to qualified institutional buyers eligible under Rule 144A of the Securities Act of 1933, as amended (the "Securities Act"). Net proceeds from the offering were approximately $433.1 million after the issuance discount and deducting offering expenses of approximately $9.5 million. We used such proceeds to fund a portion of the Forest Acquisition purchase price.

Private Placement of 6.0% Convertible Perpetual Preferred Stock. In December 2009, we completed a private placement of 2,000,000 shares of our 6.0% convertible perpetual preferred stock to an institutional investor in a transaction exempt from registration under Regulation D under the Securities Act. Net proceeds were approximately $199.9 million and were used to fund a portion of the Forest Acquisition purchase price and for general corporate purposes.

Each share of the 6.0% convertible perpetual preferred stock has a liquidation preference of $100.00 and is entitled to an annual dividend of $6.00 payable semi-annually in cash, common stock or any combination thereof, beginning on July 15, 2010. Additionally, each share is initially convertible into 9.21 shares of our common stock, at the holder's option, at any time on or after February 1, 2010 based on an initial conversion price of $10.86 and subject to customary adjustments in certain circumstances. Five years after their issuance, all outstanding shares of the convertible preferred stock will be converted automatically into shares of our common stock at the then-prevailing conversion price as long as all dividends accrued at that time have been paid.

2010 Capital Expenditure Budget. On February 25, 2010, we introduced 2010 production guidance of 130 Bcfe based on 2010 capital expenditure guidance of $860.0 million. See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for further discussion of our liquidity and capital expenditures budget.

Crusader Acquisition Bid Withdrawal. In September 2009, we entered into a Stock Purchase Agreement (the "Crusader Purchase Agreement") with Crusader Energy Group Inc., and its subsidiaries (collectively, "Crusader") to purchase all of the shares of common stock of Crusader that were to be issued upon the effectiveness of Crusader's reorganization under Chapter 11 of the United States Bankruptcy Code. On November 12, 2009, we announced our withdrawal from the acquisition process of Crusader as permitted under the bidding procedures applicable to Crusader's bankruptcy. On December 14, 2009, we terminated the Crusader Purchase Agreement, and on December 31, 2009, we received the break-up fee of $7.0 million provided for in the Crusader Purchase Agreement.

Business Strategy

Our primary objective is to achieve long-term growth and maximize stockholder value over multiple business cycles by pursuing the following strategies:

- *Growth Through Development, Drilling and Exploration of Existing Acreage.* We expect to generate long-term reserve and production growth by exploring, drilling and developing our large acreage position. Our primary exploration and development focus will be in the WTO and the Permian Basin. We have identified approximately 5,500 potential drilling locations in the WTO and believe that we will be able to expand the number of drilling locations through exploratory drilling and use of our 3-D seismic data. We intend to complement our program in the WTO through continued development of our oil reserves in the Central Basin Platform of the Permian Basin.
- *Apply Technological Improvements to Our Development and Exploration Program.* We use our 3-D seismic data and our enhanced interpretation technologies to improve drilling and exploration success. We strive to maximize value by continuing to minimize time from spud to first sales with advanced drilling, completion and production methods.

- *Reduce Costs, Enhance Returns and Maintain Operating Flexibility by Controlling Operations.* We operate 95% of our production in the WTO, Permian Basin, East Texas, the Gulf Coast area, the Mid-Continent and the Gulf of Mexico, in addition to controlling our fleet of drilling rigs. We believe this allows us to better control overall costs and maintain a high degree of operating flexibility, which permits us to manage our operating costs and control capital expenditures and the timing of development and exploration activities.

Our Business Segments and Primary Operations

We operate in three business segments: exploration and production, drilling and oil field services and midstream gas services. Financial information regarding each segment is provided in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Exploration and Production

We explore for, develop and produce natural gas and oil reserves, with a focus on increasing our reserves and production in the WTO and the Permian Basin. We operate substantially all of our wells in these areas. We also have significant operated leasehold positions in the Cotton Valley Trend in East Texas, the Gulf Coast area, the Mid-Continent and the Gulf of Mexico.

The following table identifies certain information concerning our exploration and production business as of December 31, 2009 unless otherwise noted:

Area	Estimated Net Proved Reserves (Bcfe)	PV-10 (in millions)(1)	Daily Production (MMcfe/d)(2)	Reserves/ Production (Years)	Proved Gross Acreage	Net Acreage	Number of Identified Potential Drilling Locations
WTO	340.0	$ 224.3	123.4	7.5	682,770	562,626	5,521
Permian Basin	574.8	885.0	67.6	23.3	204,110	138,691	2,610
East Texas	109.3	104.8	34.6	8.7	47,087	37,849	1,505
Gulf Coast	53.7	107.2	26.5	5.6	68,173	46,598	36
Mid-Continent	65.1	78.0	23.6	7.6	636,653	439,802	2,333
Gulf of Mexico	43.3	56.2	17.8	6.7	70,470	26,230	14
Tertiary recovery — West Texas	125.7	105.1	2.8	123.0	9,946	8,852	84
Other	0.3	0.4	—	—	1,700	1,467	—
Total	1,312.2	$1,561.0	296.3	12.1	1,720,909	1,262,115	12,103

(1) PV-10 generally differs from Standardized Measure of Discounted Net Cash Flows ("Standardized Measure") because it does not include the effects of income taxes on future net revenues; however, due to the full valuation allowance on our deferred tax asset at December 31, 2009 that serves to reduce to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009. For a reconciliation of PV-10 to Standardized Measure, see — "Proved Reserves." Our Standardized Measure was $1.6 billion at December 31, 2009.

(2) Average daily net production for the month of December 2009.

West Texas Overthrust ("WTO")

We have drilled and developed natural gas in the WTO since 1986. This area is located in Pecos County and Terrell County in West Texas and is associated with the Marathon-Ouachita fold and thrust belt that extends east-northeast across the United States into the Appalachian Mountain Region. The WTO was created by the collision of the ancestral North American and South American continents resulting in source rock and reservoir rock, including potential hydrocarbon traps, becoming thrusted upon one another in multiple layers (also known as imbricate stacking) along the leading edge of the WTO. The collision and thrusting resulted in the reservoir rock becoming highly fractured, increasing the likelihood of conventional natural gas and oil accumulations in the reservoir rock and creating a unique geological setting in North America. The primary reservoir rocks in the WTO range in depth from 2,000 to 17,000 feet and range in geologic age from the Permian to the Devonian. The imbricate stacking of these conventional gas-prone reservoirs provides for multi-pay exploration and development opportunities. Despite this, the WTO has historically been under-explored. The high CO_2 content of the natural gas, lack of infrastructure in the region, historical limitations of conventional subsurface geological and geophysical methods and commodity prices have combined to discourage exploration of the area. Our access to and control of the necessary infrastructure combined with the application of modern seismic techniques allow us to continue to identify exploration and development opportunities in the WTO.

3-D Seismic Program. In 2007, we began a multi-year seismic program to acquire 1,500 square miles of modern 3-D seismic data in the WTO. We believe this enhanced 3-D seismic program will lower exploratory drilling risk and improve completion efficiency by identifying structural detail of potential reservoirs. With the aid of 3-D seismic data and historical well information, we believe we can high-grade our drilling locations in order to achieve low finding costs. As of December 31, 2009, we had acquired 1,300 square miles of 3-D seismic data, all of which has been processed and interpreted.

Piñon Field. The Piñon Field lies along the leading edge of the WTO in Pecos County and is our most significant producing field, accounting for 25.8% of our proved reserve base as of December 31, 2009 and approximately 47% of our 2009 exploration and development expenditures (including land and seismic acquisitions). The primary reservoirs are the Tesnus sands (depths ranging from 3,500 to 5,000 feet), the Warwick Caballos chert (depths ranging from 5,000 to 8,000 feet) and the Dugout Creek Caballos chert (depths ranging from 7,000 to 10,000 feet). During 2009, we expanded the Piñon Field utilizing data from our 3-D seismic program and historical well information to identify new reservoirs in the field's three primary thrusts (Dugout Creek, Warwick and Frog Creek). As of December 31, 2009, our estimated proved natural gas and oil reserves in the Piñon Field were 338.2 Bcfe, 4.6% of which were proved undeveloped reserves based on estimates prepared by Netherland, Sewell & Associates, Inc., an independent oil and gas consulting firm. Our interests in the Piñon Field as of December 31, 2009 included 724 gross (690.9 net) producing wells and a 95.3% average working interest in the producing area of the Piñon Field. We were operating eight drilling rigs in the Piñon Field as of December 31, 2009 and we drilled 57 wells in this field during 2009.

The most productive reservoir in the Piñon Field is the Warwick Caballos chert high CO_2 reservoir. However, CO_2 is a waste product and we cannot produce high CO_2 gas without removing the CO_2 from the gas stream. Production from this reservoir is currently limited by treating capacity at our legacy natural gas treating plants. Our current expansion of the capacity of our existing plants and the construction of the Century Plant, discussed below, will expand CO_2 treating capacity in the area and will allow us to accelerate the development of the Warwick thrust.

West Texas Overthrust Exploration Update. Exploration efforts during the fourth quarter of 2009 continued to focus on the integration of 1,300 square miles of 3-D seismic data and evolving sub-surface geologic models. The first two wells of our exploratory program will begin drilling during the first quarter of 2010 and will test structures of greater than 10,000 acres in size.

Century Plant. In June 2008, we entered into an agreement with a subsidiary of Occidental Petroleum Corporation ("Occidental") to construct a CO_2 treating plant (the "Century Plant"), associated CO_2 compression pipeline facilities and ancillary equipment for $800.0 million. Occidental will pay a minimum of 100% of the contract price (including any subsequent agreed-on revisions) to us through periodic cost reimbursements based upon the percentage of the project completed. The Century Plant, to be located in Pecos County, Texas, is designed to have treating capacity of 800 MMcf per day of natural gas and is expected to be completed in two phases. The start-up of Phase 1 is anticipated in mid 2010. Century Plant Phase 1 will add approximately 400 MMcf per day of CO_2 treating capacity. Century Plant Phase 2 is expected to come online in the second half of 2011.

Upon start-up, the Century Plant will be owned and operated by Occidental. We will deliver high CO_2 natural gas to the Century Plant pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, and Occidental will separate and remove the CO_2 from the delivered natural gas. Occidental will retain substantially all CO_2 removed at the Century Plant and our other existing CO_2 treating plants. We will retain all methane from the Century Plant and our other existing plants.

Permian Basin

The Forest Acquisition expanded our holdings in the Central Basin Platform ("CBP") of the Permian Basin and added significant Permian Basin production in the Midland and Delaware Basins in Texas as well as the Northwest Shelf in New Mexico.

The primary reservoirs in the CBP are the dolomites and limestones of the San Andres and Clear Fork formations. To date, the San Andres and Clear Fork zones have produced in excess of 2.1 and 1.8 billion barrels of oil, respectively, with typical well depths ranging from 4,500 to 8,000 feet. Our properties in the CBP are positioned for infill and step-out drilling to target these reservoirs in several of the major CBP fields, such as the Goldsmith, Fullerton, Tex-Mex, Martin and Robertson fields.

Our primary target in the Midland Basin is the Spraberry and Wolfcamp formation. The Spraberry is the basinal sandstone equivalent of the Clear Fork platform carbonate and has produced approximately 1.3 billion barrels of oil to date from wells with typical depths ranging from 9,000 to 11,000 feet.

As of December 31, 2009, our estimated net proved reserves in the Permian Basin were 574.8 Bcfe, 54% of which were proved undeveloped reserves based on estimates provided by our independent oil and gas consulting firms, Lee Keeling and Associates, Inc. and Netherland, Sewell & Associates, Inc. Our interests in the Permian Basin as of December 31, 2009 included 1,472 gross (1,386.9 net) producing wells with an average working interest of 94%. We were operating four rigs in the Permian Basin as of December 31, 2009.

East Texas — Cotton Valley Trend

We own significant natural gas and oil interests in the natural gas bearing Cotton Valley Trend, which covers parts of East Texas and northern Louisiana. As of December 31, 2009, we held interests in 47,087 gross (37,849 net) acres in East Texas. At that time, our estimated net proved reserves in East Texas were 109.3 Bcfe, with net production of approximately 34.6 MMcfe per day for the month of December 2009. We focus our operations in the Cotton Valley Trend on the tight sand reservoirs of the Pettit and Travis Peak formations with depths ranging from 6,500 to 10,500 feet. These sands are typically distributed over a large area, which has led to a near 100% drilling success rate in this area. Due to the tight nature of the reservoirs, significant hydraulic fracture stimulation is required to obtain commercial production rates and efficiently drain the reservoir. Production in this area is generally characterized as long-lived, with wells having high initial production and decline rates that stabilize at lower levels after several years. Moreover, area operators continue to focus on infill development drilling as many areas have been down spaced to 40 acres per well, with some areas down-spaced to 20 acres per well. We drilled 17 gross (16.3 net) wells in the Cotton Valley Trend in 2009. As of December 31, 2009, we had two rigs running in this region.

Gulf Coast

As of December 31, 2009, we owned natural gas and oil interests in 68,173 gross (46,598 net) acres in the Gulf Coast area, which encompasses the large coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. As of December 31, 2009, our estimated net proved reserves in the Gulf Coast area were 53.7 Bcfe, with net production of approximately 26.5 MMcfe per day for the month of December 2009.

Mid-Continent

We own interests in properties in Oklahoma, Arkansas and southern Kansas that make up our Mid-Continent area. As of December 31, 2009, we held interests in 636,653 gross (439,802 net) leasehold and option acres in these areas. As of December 31, 2009, our estimated proved reserves in the Mid-Continent area were 65.1 Bcfe, based on estimates prepared by our internal engineers. Our average daily net production for the month of December 2009 was approximately 23.6 MMcfe per day.

Gulf of Mexico

As of December 31, 2009, we owned natural gas and oil interests in 70,470 gross (26,230 net) acres in state and federal waters off the coast of Texas and Louisiana. As of December 31, 2009, our estimated net proved reserves in the Gulf of Mexico were 43.3 Bcfe, with net production of approximately 17.8 MMcfe per day for the month of December 2009. Our operations in the Gulf of Mexico extend from the coast to more than 100 miles offshore and occur in waters ranging from 30 feet to 1,100 feet.

Tertiary Oil Recovery

We currently operate one active CO_2 flood and two waterfloods in which CO_2 pilot projects are currently under development. All three floods are located in the Permian Basin area of West Texas. The Wellman Unit, located in Terry County, is an active CO_2 flood in which CO_2 injection was re-initiated in November of 2005. The two prospective CO_2 pilot waterfloods are the George Allen Unit and the South Mallet Unit, located in Gaines and Hockley Counties. Both of these pilot projects are expected to begin CO_2 injection during 2010.

The three enhanced recovery projects were producing 465 net Boe per day during 2009 and have produced a total of 113.5 MMboe to date. As of December 31, 2009, net proved reserves attributable to the three properties were 20.7 MMboe. Expansion opportunities exist in all three projects. Potential expansion opportunities will be evaluated based on early performance results.

Proved Reserves

The following historical estimates of net proved natural gas and oil reserves are based on reserve reports as of December 31, 2009, December 31, 2008 and December 31, 2007, substantially all of which were prepared by independent petroleum engineers. The PV-10 and Standardized Measure shown in the table below are not intended to represent the current market value of our estimated natural gas and oil reserves. The reserve reports as of December 31, 2009 were based on our current drilling schedule and the average price during the 12-month period ended December 31, 2009, using the first-day-of-the-month price for each month. Reserve reports for years prior to 2009 were based on natural gas and oil prices at year-end. We estimate that 97.8% of our current proved undeveloped reserves will be developed by 2012 and all of our current proved undeveloped reserves will be developed by 2015. Refer to "Risk Factors" in Item 1A of this report and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report in evaluating the material presented below.

Our reserve estimation effort is overseen by our Executive Vice President — Reservoir Engineering, a registered Professional Engineer since 1988 with approximately 29 years of industry experience. Internal controls within the reserve estimation process include: confirmation that reserve estimations include all properties owned;

confirmation that reserve estimations are based upon proper working and net revenue interests for included properties; review and use in the estimation process of data provided by other departments within the Company such as Accounting; comparison and reconciliation of internally generated reserve estimations to those prepared by third parties; and review and approval of reserve volumes and valuation by appropriate executive-level management. Additionally, our Reservoir Engineering personnel monitor emerging issues and changes in guidance related to reserve estimation on an ongoing basis.

Netherland, Sewell & Associates, Inc., prepared reports of estimated proved reserves of natural gas and oil for our net interest in certain natural gas and oil properties located primarily in the WTO and East Texas, constituting approximately 51.7% of our total proved reserves as of December 31, 2009, approximately 90.2% of our total proved reserves as of December 31, 2008 and approximately 89.0% of our total proved reserves as of December 31, 2007. Lee Keeling and Associates, Inc., prepared reports of estimated proved reserves of natural gas and oil for our net interest in the natural gas and oil properties we acquired in the Forest Acquisition, which constituted approximately 33.7% of our total proved reserves as of December 31, 2009. DeGolyer and MacNaughton prepared the reports of estimated proved reserves for our tertiary oil reserves located in West Texas, which constituted approximately 9.6% of our total proved reserves as of December 31, 2009, approximately 5.4% of our total proved reserves as of December 31, 2008 and approximately 8.0% of our total proved reserves as of December 31, 2007. The remaining 5.0%, 4.4% and 3.0% of our estimated proved reserves as of December 31, 2009, 2008 and 2007, respectively, were based on internally prepared estimates.

A summary of our proved natural gas and oil reserves, all of which are located in the continental United States, is presented below:

	December 31,		
	2009	2008	2007
Estimated Proved Reserves(1)			
Developed			
Natural gas (Bcf)(2)	592.8	851.4	590.4
Oil (MMBbls)	38.3	15.3	12.5
Total proved developed (Bcfe)	822.8	943.4	665.6
Undeveloped			
Natural gas (Bcf)(2)	87.3	1,048.3	706.7
Oil (MMBbls)	67.0	27.8	24.0
Total proved undeveloped (Bcfe)	489.4	1,215.2	850.6
Total Proved			
Natural gas (Bcf)(2)	680.1	1,899.6	1,297.0
Oil (MMBbls)	105.3	43.2	36.5
Total proved (Bcfe)	1,312.2	2,158.6	1,516.2
PV-10 (in millions)(3)	$1,561.0	$2,258.5	$3,550.5
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$1,561.0	$2,220.6	$2,718.5

(1) Our estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using a 12-month average price for natural gas and oil for the year ended December 31, 2009 and year-end prices for natural gas and oil as of December 31, 2008 and 2007. The prices used in our external and internal reserve reports yield weighted average wellhead prices of $3.41 per Mcf of natural gas and $49.98 per barrel of oil at December 31, 2009, $4.94 per Mcf of natural gas and $39.42 per barrel of oil at December 31, 2008 and $6.46 per Mcf of natural gas and $87.47 per barrel of oil at December 31, 2007 based on index prices used ($3.87 per Mcf of natural gas and $57.65 per barrel of oil at December 31, 2009, $5.71 per Mcf of natural gas and $41.00 per barrel of oil at December 31, 2008 and $6.80 per Mcf of natural gas and $92.50 per barrel of oil at December 31, 2007).

(2) Given the nature of our natural gas reserves, a significant amount of our production, primarily in the WTO, contains natural gas high in CO_2 content. These figures are net of volumes of CO_2 in excess of pipeline quality specifications.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved natural gas and 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 for periods prior to December 31, 2009 and 12-month average prices for the year ended December 31, 2009. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues; however, due to the full valuation allowance on our deferred tax asset at December 31, 2009 that serves to reduce to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and 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,		
	2009	**2008**	**2007**
		(In millions)	
Standardized Measure of Discounted Net Cash Flows	$1,561.0	$2,220.6	$2,718.5
Present value of future income tax expense discounted at 10%	—	37.9	832.0
PV-10	$1,561.0	$2,258.5	$3,550.5

(4) Standardized Measure represents the present value of estimated future cash inflows from proved natural gas and 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 are used to calculate PV-10. Standardized Measure differs from PV-10 as Standardized Measure includes the effect of future income taxes; however, due to the full valuation allowance on our deferred tax asset at December 31, 2009 that serves to reduce to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009.

Proved Reserves – Sensitivity Analysis

The table below presents a comparison of our proved reserve quantities and PV-10 when calculated (1) using the 12-month average price (NYMEX price of $3.87 per Mcf of natural gas and West Texas Intermediate posted price of $57.65 per barrel of oil, NYMEX equivalent of $61.14 per barrel) in accordance with the SEC final rule, *Modernization of Oil and Gas Reporting Requirements,* effective December 31, 2009, and (2) the NYMEX spot prices at December 31, 2009 ($5.79 per Mcf of natural gas and $79.34 per barrel of oil). Prices above are before adjustments for field differentials, although field differentials are applied in the computation below. Cost assumptions were held constant for both calculations.

	Proved Reserves at December 31, 2009			
Price Case Scenario	**Natural Gas (Bcf)**	**Oil (MBbls)**	**Total (Bcfe)**	**PV-10(1) (in millions)**
12-Month Average	680.1	105.3	1,312.2	$1,561.0
December 31, 2009 Spot Price	1,840.3	120.9	2,565.7	$3,589.5

(1) The following table provides a reconciliation of our Standardized Measure to PV-10 calculated under each pricing scenario as of December 31, 2009:

	12-Month Average	**Spot Price**
	(In millions)	
Standardized Measure of Discounted Net Cash Flows	$1,561.0	$1,561.0
Effect of Change in Price on Existing Quantities	—	1,508.8
Discounted Future Net Values of Quantities Added Under Alternate Price Scenario	—	519.7
PV-10	$1,561.0	$3,589.5

We believe the estimation of reserve quantities and PV-10 based upon the December 31, 2009 spot price is a useful comparison to our reserve calculation as of December 31, 2008, which also was based on year end spot prices under SEC rules then in effect. The reserves presented under the alternative price assumption are not calculated in accordance with current SEC rules and have not been reviewed by independent petroleum engineers.

Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. To be classified as proved reserves, the project to extract the oil or gas must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. In determining the amount of proved reserves, the price used must be the average price during the 12-month period prior to the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

In January 2010, the Financial Accounting Standards Board issued Accounting Standards Update 2010-03 ("ASU 2010-03") to align the oil and gas reserve estimation and disclosure requirements of Extractive Industries — Oil and Gas Topic of the Accounting Standards Codification with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements*. Key items in the new rules include changes to the pricing used to estimate reserves and calculate the full cost ceiling limitation whereby a 12-month average price is used rather than a single day spot price, the use of new technology for determining reserves, the ability to include nontraditional resources in reserves and permitting disclosure of probable and possible reserves. We implemented ASU 2010-03 as of December 31, 2009.

Proved Undeveloped Reserves. During 2009, the Company drilled 72 wells and invested approximately $93.1 million dollars in the development of properties that were classified as proved undeveloped at December 31, 2008. At December 31, 2009, 65 of these wells were classified as proved developed producing properties with the remaining wells still in progress.

The 12-month average natural gas index price of $3.87 per Mcf used in the estimation of reserves as of December 31, 2009 resulted in downward revisions of quantities associated with the Company's proved undeveloped properties as a significant number of properties generated no PV-10 value resulting in the elimination of associated reserve quantities and a shortening of the productive lives of certain proved properties that became uneconomic earlier in their lives with the use of lower natural gas prices compared to prices used in the estimation of reserves in previous periods. There were no downward revisions as a result of the 12-month average oil index price used in the estimation of reserves as of December 31, 2009.

Production and Price History

The following tables set forth information regarding our net production of natural gas, oil and natural gas liquids and certain price and cost information for each of the periods indicated. Because of the relatively high volumes of CO_2 produced with natural gas in certain areas of the WTO, our reported sales and reserves volumes and the related unit prices received for natural gas in these areas are reported net of CO_2 volumes stripped at the gas plants. The gas plant fees for removing CO_2 for our high CO_2 natural gas have been included in our lease operating expenses as treating and gathering fees. All natural gas delivered to sales points with CO_2 levels within pipeline specifications is included in sales and reserves volumes.

	Year Ended December 31,		
	2009	2008	2007
Production Data:			
Natural gas (MMcf)	87,461	87,402	51,958
Oil (MBbls)(1)	2,894	2,334	2,042
Combined equivalent volumes (MMcfe)	104,823	101,405	64,211
Average daily combined equivalent volumes (MMcfe/d)	287.2	277.1	175.9

	Year Ended December 31,		
	2009	2008	2007
Average Prices(2):			
Natural gas (per Mcf)	$ 3.36	$ 7.95	$ 6.51
Oil (per Bbl)(1)	$ 55.62	$ 91.54	$ 68.12
Combined equivalent (per Mcfe)	$ 4.34	$ 8.96	$ 7.45

(1) Includes natural gas liquids.

(2) Reported prices represent actual average prices for the periods presented and do not give effect to derivative contract settlements.

	Year Ended December 31,		
	2009	2008	2007
Expenses per Mcfe:			
Lease operating expenses:			
Transportation	$0.11	$0.11	$0.12
Processing, treating and gathering(1)	0.36	0.33	0.28
Other lease operating expenses	1.14	1.13	1.25
Total lease operating expenses	$1.61	$1.57	$1.65
Production taxes(2)	$0.04	$0.30	$0.30

(1) Includes costs attributable to gas treatment to remove CO_2 and other impurities from our high CO_2 natural gas.

(2) Net of severance tax refunds.

Productive Wells

The following table sets forth the number of productive wells in which we owned a working interest at December 31, 2009. Productive wells consist of producing wells and wells capable of producing, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas		Oil		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
WTO	722	686.4	14	13.2	736	699.6
Permian Basin	75	64.1	1,397	1,322.8	1,472	1,386.9
East Texas	255	233.0	1	0.7	256	233.7
Gulf Coast	118	74.1	21	10.7	139	84.8
Mid-Continent	557	217.3	72	27.7	629	245.0
Gulf of Mexico	19	7.4	26	17.0	45	24.4
Tertiary recovery — West Texas	—	—	49	46.0	49	46.0
Other	—	—	47	0.8	47	0.8
Total	1,746	1,282.3	1,627	1,438.9	3,373	2,721.2

Developed and Undeveloped Acreage

The following table sets forth information regarding our developed and undeveloped acreage at December 31, 2009:

	Developed Acreage(1)		Undeveloped Acreage(2)	
Area	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
WTO	31,743	29,501	651,027	533,125
Permian Basin	126,535	99,804	77,575	38,887
East Texas	27,202	23,639	19,885	14,210
Gulf Coast	61,550	43,411	6,623	3,187
Mid-Continent	128,368	68,472	508,285	371,330
Gulf of Mexico	65,039	20,799	5,431	5,431
Tertiary recovery — West Texas	9,306	8,525	640	327
Other	180	21	1,520	1,446
Total	449,923	294,172	1,270,986	967,943

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth as of December 31, 2009 the expiration periods of the gross and net acres that are subject to leases in the acreage summarized in the above table.

Twelve Months Ending	Acres Expiring Gross	Net
December 31, 2010	263,868	205,684
December 31, 2011	501,162	396,219
December 31, 2012	284,042	180,371
December 31, 2013 and later	188,823	172,969
Other(1)	33,091	12,700
Total	1,270,986	967,943

(1) Leases remaining in effect until the cessation of development efforts or cessation of production on the developed portion of the particular lease.

Drilling Activity

The following table sets forth information with respect to wells we completed during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Gross wells refer to the total number of wells in which we had a working interest and net wells refer to gross wells multiplied by our weighted average working interest. As of December 31, 2009, we had 27 wells drilling or awaiting completion.

	2009				2008				2007			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	147	97.4%	117.2	97.9%	398	98.5%	372.4	98.5%	281	99.3%	244.4	99.5%
Dry	4	2.6%	2.5	2.1%	6	1.5%	5.7	1.5%	2	0.7%	1.3	0.5%
Total	151	100.0%	119.7	100.0%	404	100.0%	378.1	100.0%	283	100.0%	245.7	100.0%
Exploratory:												
Productive	9	100.0%	8.6	100.0%	48	96.0%	46.4	95.9%	27	81.8%	24.3	83.8%
Dry	—	—	—	—	2	4.0%	2.0	4.1%	6	18.2%	4.7	16.2%
Total	9	100.0%	8.6	100.0%	50	100.0%	48.4	100.0%	33	100.0%	29.0	100.0%
Total:												
Productive	156	97.5%	125.8	98.1%	446	98.2%	418.8	98.2%	308	97.5%	268.7	97.8%
Dry	4	2.5%	2.5	1.9%	8	1.8%	7.7	1.8%	8	2.5%	6.0	2.2%
	160	100.0%	128.3	100.0%	454	100.0%	426.5	100.0%	316	100.0%	274.7	100.0%

Drilling Rigs

The following table sets forth information with respect to the rigs operating on our acreage as of December 31, 2009.

Area	Owned	Third-Party
WTO	8	—
Permian Basin	4	—
East Texas	2	—
Mid-Continent	—	1
Total	14	1

Marketing and Customers

We sell natural gas, oil and natural gas liquids to a variety of customers, including utilities, natural gas and oil companies and trading and energy marketing companies. One of these customers, Plains Energy, accounted for 20.0%, 10.5% and 11.2% of our total revenue during 2009, 2008 and 2007, respectively. Given the number of readily available purchasers for our products, it is unlikely that the loss of a single customer in the areas in which we sell our products would materially affect our sales.

See Note 23 in the consolidated financial statements included in Item 8 of this report for information regarding our major customers.

Title to Properties

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

Drilling and Oil Field Services

The drilling and related oil field services that we provide to our exploration and production business and to third parties are described below.

Drilling Operations

We drill for our own account primarily in West Texas through our drilling and oil field services subsidiary, Lariat. In addition, we also drill wells for other natural gas and oil companies, primarily located in the West Texas region. We believe that drilling with our own rigs allows us to control costs and maintain operating flexibility. Our rig fleet is designed to drill in our specific areas of operation and has an average of over 800 horsepower and an average depth capacity of greater than 10,500 feet. As of December 31, 2009, our drilling rig fleet consisted of 30 operational rigs. As of December 31, 2009, 14 of our rigs were working on properties that we operated.

The table below identifies certain information concerning our contract drilling operations and our directly-owned rigs:

	Year Ended December 31,		
	2009	2008	2007
Number of operational rigs owned at end of period	30	28	25
Average number of operational rigs owned during the period	30.0	27.6	26.0
Average drilling revenue per day per rig working for third parties(1)(2)	$11,398	$14,217	$21,468

(1) Represents revenues from our rigs working for third parties divided by the total number of days our drilling rigs were used by third parties during the period.

(2) Does not include revenues for related rental equipment.

The table below identifies certain information concerning our drilling rigs as of December 31, 2009:

	Operating for			
	SandRidge	Third Parties	Idle	Operational
Lariat	14	2	14	30

Types of Drilling Contracts

We obtain our contracts for drilling natural gas and oil wells either through competitive bidding or through direct negotiations with customers. Our drilling contracts generally provide for compensation on a day work basis. The contract terms we offer generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, the anticipated duration of the work to be performed and prevailing market rates. For a discussion of these contracts, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Segment Overview — Drilling and Oil Field Services Segment" in Item 7 of this report.

Oil Field Services

Our oil field services business began in 1986 and conducts operations that together with our drilling services compliment our exploration and production business. Oil field services include providing pulling units, trucking, rental tools, location and road construction and roustabout services to us as well as to third parties.

Our Customers

We perform approximately 90% of our drilling and oil field services in support of our exploration and production segment and approximately 10% for other operators. For the year ended December 31, 2009, we generated revenues of $23.6 million for drilling and oil field services performed for third parties, with Pioneer Natural Resources USA, Inc., accounting for approximately $8.6 million of those revenues.

Capital Expenditures

Our capital expenditures for 2009 related to our drilling and oil field services were $4.1 million. We have budgeted approximately $5.0 million in capital expenditures in 2010 for our drilling and oil field services segment.

Midstream Gas Services

We provide gathering, compression, processing and treating services of natural gas in West Texas. Our midstream operations and assets not only serve our exploration and production segment, but also service other natural gas and oil companies. The following tables set forth information regarding our primary midstream assets as of December 31, 2009:

Gas Treating Plants (West Texas)	Plant Capacity (MMcf/d)	Average Utilization(1)	Third-Party Usage
Pike's Peak	90	93%	<1%
Grey Ranch	220	88%	7%

(1) Average utilization for the year ended December 31, 2009.

SandRidge CO_2 Compression Facilities (West Texas)	CO_2 Compression Capacity (MMcf/d)	Average Utilization(1)
Pike's Peak	36	82%
Mitchell	26.5	83%
Grey Ranch	88	47%
Terrell	28	82%

(1) Average utilization for the year ended December 31, 2009.

West Texas

In Pecos County, we own and operate the Pike's Peak gas treating plant, which has the capacity to treat 90 MMcf per day of natural gas for the removal of CO_2 from natural gas produced in the Piñon Field and nearby areas. We also own the Grey Ranch CO_2 treatment plant located in Pecos County and have a 50% interest in the partnership that leases the plant from us under a lease expiring in 2020. In October 2009, we took over operations at the Grey Ranch plant pursuant to an agreement with such partnership. The treating capacities for both the Pike's Peak and Grey Ranch plants are dependent upon the quality of natural gas being treated. The data included in the table above for the Pike's Peak and Grey Ranch plants is based on a natural gas stream that averaged 65% CO_2.

Our two West Texas gas treating plants remove CO_2 from natural gas production and deliver residue gas into the Atmos Lone Star and Enterprise Energy Services pipelines. These assets are operated on fixed fees based upon throughput of natural gas. In addition, we have access for up to 80 MMcf per day of treating capacity at Hoover Energy Partners' Mitchell Plant under a long-term fixed fee arrangement.

We also own or operate approximately 800 miles of natural gas gathering pipelines and numerous dehydration units. Within the Piñon Field, we operate separate gathering systems for sweet natural gas and produced natural gas containing high percentages of CO_2. In addition to servicing our exploration and production business, these assets also service other natural gas and oil companies.

The majority of the produced natural gas gathered by our midstream assets in West Texas requires compression from the wellhead to the final sales meter. As of December 31, 2009, we owned or operated approximately 82,000 horsepower of gas compression in West Texas. We anticipate installing an additional 24,000 horsepower in 2010.

In June 2009, we completed the sale of the gathering and compression assets owned by us and located in the Piñon Field at that time. In conjunction with the sale, we entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, we have dedicated the Piñon Field acreage for priority gathering services for a period of 20 years and we will pay a fee that was negotiated at arms' length for such services.

Other Areas

As of December 31, 2009, we owned approximately 116 miles of pipeline gathering systems and operated more than 11,000 horsepower of natural gas compression in East Texas. We anticipate installation of an additional 2,700 horsepower in East Texas in 2010. We also owned approximately 50 miles of pipeline gathering systems and operated over 4,000 horsepower of gas compression in the Gulf Coast area, and owned approximately 44 miles of pipeline in the Mid-Continent area.

Capital Expenditures

The growth of our midstream assets is driven by our exploration and development operations. Historically, pipeline and facility expansions are made when warranted by the increase in production or the development of additional acreage. During 2009, we spent approximately $50.0 million in capital expenditures to install pipeline and compression infrastructure to accommodate our growth in production and for increased treating capacity for high CO_2 gas, adding approximately 70 MMcf per day in additional treating capacity. With the startup of the Century Plant in mid 2010, we anticipate adding access to approximately 400 MMcf per day in additional treating capacity in 2010. We have budgeted approximately $105.0 million in 2010 capital expenditures for our midstream gas services segment and other general purposes.

Marketing

Through Integra Energy LLC, our wholly owned subsidiary, we buy and sell natural gas from SandRidge-operated wells and third-party-operated wells within our West Texas operations. We generally buy and sell natural gas on "back-to-back" contracts using a portfolio of baseload and spot sales agreements. Identical volumes are bought and sold on monthly and daily contracts using a combination of *Inside FERC* and *Gas Daily* pricing indices to eliminate price exposure.

We do not actively seek to buy and sell third-party natural gas due to onerous credit requirements and minimal margin expectations. We conduct thorough credit checks with all potential purchasers and minimize our exposure by contracting with multiple parties each month. We do not engage in any hedging activities with respect to these contracts. We manage several interruptible natural gas transportation agreements in order to take advantage of price differentials or to secure available markets when necessary. We currently have 100,000 MMBtu per day of firm transportation service subscribed on the Oasis Pipeline and 75,000 MMBtu per day on the Mid-Continent Express Pipeline for a portion of our Piñon Field production for 2010.

Other Operations

Our CO_2 capturing operations are conducted through SandRidge CO_2. As of December 31, 2009, SandRidge CO_2 owned 239 miles of CO_2 pipelines in West Texas with approximately 63,000 horsepower of owned and leased CO_2 compression available and currently operational. The captured CO_2 is primarily used and sequestered in tertiary oil recovery operations. As of December 31, 2009, SandRidge CO_2 was capturing approximately 140 MMcf per day of CO_2. We delivered the majority of this to Occidental Permian Ltd. and Chevron Corp. In December 2009, we captured and sold an average of 104 MMcf of CO_2 per day and utilized 11.0 MMcf per day in our enhanced oil recovery projects.

Future regulation of greenhouse gas emissions may provide us an opportunity to create economic benefits in the form of Emissions Reduction Credits ("ERCs"), but such regulation may also impose burdens on the conduct and cost of our operations. Legislative and regulatory efforts may result in legal requirements that create a more active and more valuable market in which to trade ERCs, although the timing and scope of future legal requirements governing greenhouse gases remain uncertain. We currently capture approximately 2.2 million metric tonnes of CO_2 per year, all of which is utilized in enhanced oil recovery projects. The captured CO_2 may prove beneficial to us if the CO_2 capture results in ERCs that can be traded or used by us to meet future regulatory compliance obligations that may otherwise be costly to satisfy. ERCs of just over 1.2 million metric tonnes were sold on the voluntary market during 2009. See "— Environmental Regulations — Future Laws and Regulations."

Competition

We believe that our leasehold acreage position, drilling and oil field services businesses, midstream assets, CO_2 supply and technical and operational capabilities generally enable us to compete effectively. However, the oil and gas industry is intensely competitive, and we face competition in each of our business segments.

We believe our geographic concentration of operations and vertical integration enables us to compete effectively with other exploration and production operations. However, we compete with many companies that have greater financial and personnel resources than we do. These companies may be able to pay more for producing properties and undeveloped acreage. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil market prices. Our larger or fully integrated competitors may be able to absorb the burden of any existing and future federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future depends on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties.

With respect to our drilling business, we believe the type, age and condition of our drilling rigs, the quality of our crews and the responsiveness of our management generally enable us to compete effectively. However, to the extent we drill for third parties, we encounter substantial competition from other drilling contractors. Our primary market area is highly competitive. The drilling contracts we compete for are usually awarded on the basis of competitive bids. We may, based on the economic environment at the time, determine that market conditions and profit margins are such that contract drilling for third parties is not a beneficial use of our resources.

We believe pricing and rig availability are the primary factors our potential customers consider in determining which drilling contractor to select. While we must be competitive in our pricing, our competitive strategy generally emphasizes the quality of our equipment and the experience of our rig crews to differentiate us from our competitors. This strategy is less effective when demand for drilling services is weak or there is an oversupply of rigs. These conditions usually result in increased price competition, which makes it more difficult for us to compete on the basis of factors other than price. Many of our competitors have greater financial, technical and other resources than we do. Their greater capabilities in these areas may enable them to better withstand industry downturns and better retain skilled rig personnel.

We believe our geographic concentration of operations enables us to compete effectively in our midstream business segment. Most of our midstream assets are integrated with our production. However, with respect to third-party natural gas and acquisitions, we compete with companies that have greater financial and personnel resources than we do. These companies may be able to pay more for acquisitions. In addition, these companies may have a greater ability to price their services below our prices for similar services.

We believe our supply of CO_2 and technical expertise enable us to compete effectively in our CO_2 gathering and sales business. However, we face the same competitive pressures in this business that we do in our traditional oil field services segments.

Seasonal Nature of Business

Generally, the demand for natural gas decreases during the summer months and increases during the winter months. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other natural gas and oil operations in a portion of our operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Environmental Regulations

General

We are subject to extensive and complex federal, state and local laws and regulations governing the protection of the environment and of the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling or production commences;
- require the installation of expensive pollution control equipment;
- require safety-related procedures and personal protective equipment to be used during operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with natural gas and oil drilling production, transportation and treating activities;
- suspend, limit, prohibit or require approval before construction, drilling and other activities; and
- require remedial measures to mitigate pollution from historical and ongoing operations, such as the closure of pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of natural gas and oil production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and potentially criminal penalties. The effects of these laws and regulations, as well as other laws or regulations that may be adopted in the future, could have a material adverse impact on our business, financial condition and results of operations. Below is a discussion of environmental laws and regulations that could have a material impact on our business, financial condition and results of operations.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") also known as the Superfund law, and analogous state laws impose joint and several liability, without regard to fault or legality of conduct, on specific classes of persons for the release of a hazardous substance into the environment. These persons include the current owner or operator of the site at or to which hazardous substances have been released or disposed, a former owner or operator of such site, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict joint and several liability for the costs of investigating and cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of related environmental and health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we generate wastes that may fall within CERCLA's definition of hazardous substances. Further, natural gas and oil exploration, production, treating and other activities have been conducted at some of our properties by previous owners and operators, and materials from these operations remain at and could migrate from some of our properties and may warrant or require investigation or remediation or other response action. Therefore, governmental agencies or third parties could seek to hold us responsible under CERCLA or similar state laws for all or part of the costs to clean up a site at or to which hazardous substances may have been released or deposited.

Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency ("EPA") the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of oil or natural gas are currently excluded from regulation as RCRA hazardous wastes but instead are regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain natural gas and oil exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change would likely increase our operating expenses, which could have a material adverse effect on our business, financial condition or results of operations as well as on the industry in general.

Air Emissions

The federal Clean Air Act and comparable state laws control emissions of potentially harmful air emissions through permitting and monitoring regulations. We are required to obtain various permits to ensure that emissions from our operations remain within permitted levels. To comply with the terms of these permits, and, as part of our ongoing efforts to operate in an environmentally responsible manner, we have installed and maintained complex emission control technologies throughout our systems. Additionally, our midstream operations are developing a compliance agreement with the state agency that will allow us to achieve full compliance with air emission regulations.

Water Discharges

The federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances into waters of the United States, including wetlands, as well as state waters. These laws prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and other substances related to the oil and gas industry into onshore, coastal and offshore waters without appropriate permits. Some of the pollutant limitations have become more restrictive over the years, and additional restrictions and limitations including technology requirements and receiving water limits, may be imposed in the future. The Clean Water Act also regulates storm water discharges from industrial and construction activities. Regulations promulgated by the EPA and state regulatory agencies require industries engaged in certain industrial or construction activities to acquire permits and implement storm water management plans and best management practices, to conduct periodic monitoring and reporting of discharges, and to train employees. Further, federal and state regulations require certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. There are costs associated with each of these regulatory requirements. In addition, federal and state regulatory agencies can impose administrative, civil and potentially criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990 ("OPA") which amends and augments the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. In addition, OPA and regulations that implement OPA impose requirements on responsible parties related to the prevention of oil spills and liability for clean up and natural resource damages resulting from such spills. For example, some of our facilities in the Gulf Coast region must develop, implement and maintain facility response plans, conduct annual spill training for certain employees, conduct annual spill drills and provide varying degrees of financial assurance.

National Environmental Policy Act

Natural gas and oil exploration and production activities on federal lands or otherwise requiring federal approval are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency may prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans on federal lands, require governmental permits that are subject to the requirements of NEPA. The NEPA process has the potential to delay or even prohibit our development of natural gas and oil projects in covered areas.

Greenhouse Gases Rule

In October 2009, the EPA finalized and published the Mandatory Reporting of Greenhouse Gases Rule requiring certain facilities to track and report emissions of CO_2, methane and various fluorinated hydrocarbons. The rule applies to significant sources and/or source categories of greenhouse gases and to certain suppliers of CO_2 and methane products. Generally, facilities that emit 25,000 tons per year or more of greenhouse gases are subject to this program. Initial greenhouse gas reports must be submitted to the EPA in 2011 and must cover the 2010 calendar year reporting period. The Company has reviewed the final rule and has determined that the Pikes Peak Plant, the Grey Ranch Plant, all CO_2 compression sites and several of its natural gas compression locations are subject to these monitoring and reporting requirements. The Company has utilized the services of a third party environmental consulting company to evaluate the applicable requirements and ensure adequate monitoring and recordkeeping programs are in place and that the required information will be available for submittal on or before the applicable submission deadline.

Future Laws and Regulations

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may contribute to warming the Earth's atmosphere. In response to such studies, the United States Congress is actively considering legislation to restrict or regulate emissions of greenhouse gases. More than one-third of the states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emissions inventories and regional greenhouse gas cap-and-trade programs. Also, in July 2008, the EPA issued an Advance Notice of Proposed Rulemaking regarding possible future regulation of greenhouse emissions under the Clean Air Act in response to the United States Supreme Court's decision in *Massachusetts, et al. v. EPA*, decided in 2007, which may result in the imposition of restrictions on the emission of greenhouse gases, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. In December 2009, the EPA announced a finding that greenhouse gases threaten the public's health and welfare. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the Kyoto Protocol, an international treaty pursuant to which participating countries, not including the United States, have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate-related legislation or other regulatory initiatives by Congress or various states of the United States, or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which we conduct business, may have an adverse effect on demand for our services or products and may result in compliance obligations with respect to the release, capture and use of carbon dioxide that could have an adverse effect on our operations.

Anti-Terrorism Measures

The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in 2007 regarding risk-based performance standards to be attained pursuant to the act and, on November 20, 2007, further issued an Appendix A to the interim rules establishing chemicals of interest and their respective threshold quantities that will trigger compliance with the interim rules. We have not yet determined the extent to which our facilities are subject to the interim rules or the associated costs to comply, but it is possible that such costs could be substantial.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is extensively regulated by numerous federal, state and local authorities, including Native American tribes. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;

- the timing of construction or drilling activities;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of natural gas and oil properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, oil and natural gas liquids within its jurisdiction.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restoration, in areas where we operate. Regulations of the Minerals Management Service of the United States Department of the Interior ("MMS") require that owners and operators plug and abandon wells and decommission and remove offshore facilities located in federal offshore lease areas in a prescribed manner. The MMS requires federal leaseholders to post performance bonds or otherwise provide necessary financial assurances to provide for such abandonment, decommissioning and removal. The New Mexico Oil Conservation requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Railroad Commission of Texas has financial responsibility requirements for owners and operators of facilities in state waters to provide for similar assurances. The United States Army Corps of Engineers ("ACOE") and many other state and local municipalities have regulations for plugging and abandonment, decommissioning and site restoration. Although the ACOE does not require bonds or other financial assurances, some other state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our sales of our own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess civil penalties of $1.0 million per day per violation.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines.

However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Employees

As of December 31, 2009, we had 1,694 full-time employees, including more than 186 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our 1,694 employees, 466 are located at our headquarters in Oklahoma City, Oklahoma, and the remaining employees work in our various field offices and at our drilling sites.

Glossary of Natural Gas and Oil Terms

The following is a description of the meanings of some of the oil and gas industry terms used in this report.

2-D seismic or 3-D 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 report in reference to 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 oil, condensate or natural gas liquids.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

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 well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

CO_2. Carbon dioxide.

Developed acreage. The number of acres that are assignable to productive wells.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be produced (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development Costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. Development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install, production facilities such as leases, flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry well. An exploratory, development or extension well that proves to be incapable of producing either natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

Environmental Assessment ("EA"). A study to determine whether a federal action significantly affects the environment, which federal agencies may be required by the National Environmental Policy Act or similar state statutes to undertake prior to the commencement of activities that would constitute federal actions, such as natural gas and oil exploration and production activities on federal lands.

Environmental Impact Statement. A more detailed study of the environmental effects of a federal undertaking and its alternatives than an EA, which may be required by the National Environmental Policy Act or similar state statutes, either after the EA has been prepared and determined that the environmental consequences of a proposed federal undertaking, such as natural gas and oil exploration and production activities on federal lands, may be significant, or without the initial preparation of an EA if a federal agency anticipates that a proposed federal undertaking may significantly impact the environment.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

High CO_2 gas. Natural gas that contains more than 10% CO_2 by volume.

Imbricate stacking. A geological formation characterized by multiple layers lying lapped over each other.

MBbls. Thousand barrels of 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 oil, condensate or natural gas liquids.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMboe. Million barrels of oil equivalent.

MBtu. Thousand British Thermal Units.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

MMcfe. Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of 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.

Present value of future net revenues ("PV-10"). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

Productive well. A well that is found to be capable of producing natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

Prospect. A specific geographic area that, 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. Reserves that are both proved and developed.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:

The quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically, based on prices used to estimate reserves, through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Reserves that are both proved and undeveloped.

Pulling Units. Pulling units are used in connection with completions and workover operations.

PV-10. See "Present value of future net revenues."

Rental Tools. A variety of rental tools and equipment, ranging from trash trailers to blow out preventors to sand separators, for use in the oil field.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, based on prices used to estimate reserves and as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Roustabout Services. The provision of manpower to assist in conducting oil field operations.

Standardized Measure or Standardized Measure of Discounted Future Net Cash Flows. The present value of estimated future cash inflows from proved natural gas and oil reserves, less future development and production costs and future 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 on future net revenues.

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 economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

Undeveloped oil and gas reserves. Reserves of any category 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. In that regard:

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility, based on pricing used to estimate reserves, at greater distances.

(ii) Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances are estimates for undeveloped reserves 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 projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

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.

Item 1A. *Risk Factors*

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

Our revenues, profitability and cash flow depend upon the prices and demand for natural gas and oil. 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 and oil prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas and oil;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing regions, 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, including hurricanes and tropical storms in and around the Gulf of Mexico;
- 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 oil prices, such as those experienced in recent periods, may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas and oil that we can produce economically and, therefore, could have a material adverse effect on our financial condition and results of operations. This also may result in our having to make substantial downward adjustments to our estimated proved reserves.

Volatility in the capital markets could affect the value of certain assets as well as our ability to obtain capital.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile due to a variety of factors, including significant write-offs in the financial services sector and current weak economic conditions. In some cases, the markets have produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers' underlying financial and/or operating strength. As a result, for many companies, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending 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 on similar terms or at all and reduced, or in some cases ceased, to provide funding to borrowers. In addition, lending counterparties under existing revolving credit facilities and other debt instruments may be unwilling or unable to meet their funding obligations. These factors may adversely affect the value of certain of our assets and our ability to draw on our senior credit facility. If the current credit conditions of United States and international capital markets persist or deteriorate, we may be required to impair the carrying value of assets associated with derivative contracts to account for non-performance by counterparties to those contracts. Moreover, government responses to the disruptions in the financial markets may not restore consumer confidence, stabilize the markets or increase liquidity and the availability of credit.

On October 3, 2008, Lehman Brothers Commodity Services, Inc. ("Lehman Brothers"), a lender under our senior credit facility, filed for bankruptcy. At the time that its parent, Lehman Brothers Holdings, Inc., declared bankruptcy on September 15, 2008, Lehman Brothers elected not to fund its pro rata share, or 0.29%, of borrowings requested by us under the senior credit facility. Accordingly, we anticipate that Lehman Brothers will not fund its pro rata share of any future borrowing requests. We currently do not expect this reduced availability of amounts under the senior credit facility to impact our liquidity or business operations.

If other financial institutions that have extended credit commitments to us are adversely affected by the current conditions of the United States and international capital markets, they may become unable to fund borrowings under their credit commitments to us, which could have a material adverse effect on our financial condition and our ability to borrow additional funds, if needed, for working capital, capital expenditures and other corporate purposes.

Future price declines may result in further reductions of the asset carrying values of our natural gas and oil properties.

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved natural gas and oil reserves attributable to proved properties, discounted at 10%, plus the lower of cost or market value of unproved properties. The full cost ceiling is evaluated at the end of each quarter using the most recent 12-month average prices for natural gas and oil, adjusted for the impact of derivatives accounted for as cash flow hedges. As none of our derivatives are accounted for as cash flow hedges, the impact of our derivative contracts has been excluded from the determination of our full cost ceiling. Our ceiling limitation as of December 31, 2009 resulted in a non-cash impairment charge of $388.9 million. Further declines in natural gas and oil prices, without other mitigating circumstances, could result in additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which could cause us to make additional write-downs of capitalized costs of our natural gas and oil properties and non-cash charges against future earnings. The amount of such future write-downs and non-cash charges could be substantial.

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

As of December 31, 2009, our total indebtedness was $2.6 billion, and we had preferred stock outstanding with an aggregate liquidation preference of $465.0 million. Our substantial level of indebtedness and preferred stock outstanding increases the possibility that we may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our lease and other financial obligations and contractual commitments, could have other important consequences to us. For example, it could:

- make us more vulnerable to adverse changes in general economic, industry and competitive conditions and adverse changes in government regulation;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flows to fund working capital, capital expenditures, acquisitions and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- place us at a disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness prevents us from pursuing; and
- limit our ability to borrow additional amounts for working capital, capital expenditures, acquisitions, debt service requirements, execution of our business strategy or other purposes.

Any of the above listed factors could have a material adverse effect on our business, financial condition and results of operations.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves. Our current estimates of reserves could change, potentially in material amounts, in the future.

The process of estimating natural gas and oil reserves is complex and inherently imprecise. It requires interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as natural gas and oil prices, drilling and operating expenses, capital expenditures and availability of funds. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See "Business — Our Businesses and Primary Operations" in Item 1 of this report for information about our natural gas and oil reserves.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and 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 report, which in turn could have a negative effect on the value of our assets. In addition, from time to time in the future, we may adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development, natural gas and oil prices and other factors, many of which are beyond our control.

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 and oil reserves.

We base the estimated discounted future net cash flows from our proved reserves on 12-month average prices and costs. Actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- actual prices we receive for natural gas and oil;
- the accuracy of our reserve estimates;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for natural gas and oil; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Unless we replace our natural gas and oil reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Our future natural gas and oil reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Our potential drilling location inventories are scheduled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

As of December 31, 2009, only 610 of our approximately 12,100 identified potential future well locations were attributed to proved undeveloped reserves. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

We will not know conclusively prior to drilling whether natural gas or oil will be present in sufficient quantities to be economically viable.

We describe some of our current prospects and drilling locations and our plans to explore those prospects and drilling locations in this report. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of natural gas or oil. Our prospects and drilling locations are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation.

The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in sufficient quantities to be economically viable. Even if sufficient amounts of natural gas or oil exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. During 2009, we participated in drilling a total of 160 gross wells, of which four were identified as dry wells. If we drill additional wells that we identify as dry wells in our current and future prospects, our drilling success rate may decline and materially harm our business. In summary, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

Our reviews of properties we acquire are inherently incomplete because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, we often assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on our results of operations and financial condition.

The development of the proved undeveloped reserves in West Texas and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 35.5% of the estimated proved reserves that we owned or had under lease in West Texas as of December 31, 2009 were proved undeveloped reserves and 37.3% of our total reserves were proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Therefore, ultimate recoveries from these fields may not match current expectations. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves.

A significant portion of our operations are located in West Texas, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2009, approximately 69.7% of our proved reserves and approximately 64.5% of our production were located in the WTO and Permian Basin in West Texas. In addition, a substantial portion of our WTO natural gas contains a high concentration of CO_2 and requires treating. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production from these wells caused by transportation and treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance or unanticipated occurrences. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

Many of our prospects in the WTO may contain natural gas that is high in CO_2 content, which can negatively affect our economics.

The reservoirs of many of our prospects in the WTO may contain natural gas that is high in CO_2 content. The natural gas produced from these reservoirs must be treated for the removal of CO_2 prior to marketing. If we cannot obtain sufficient capacity at treatment facilities for our natural gas with a high CO_2 concentration, or if the cost to obtain such capacity significantly increases, we could be forced to delay production and development or experience increased production costs. We do not know the amount of CO_2 we will encounter in any well until it is drilled. As a result, sometimes we encounter CO_2 levels in our wells that are higher than expected. Since the treatment expenses are incurred on a Mcf basis, we will incur a higher effective treating cost per MMBtu of natural gas sold for natural gas with a higher CO_2 content. As a result, high CO_2 gas wells must produce at much higher rates than low CO_2 gas wells to be economic, especially in a low natural gas price environment.

Furthermore, when we treat the gas for the removal of CO_2, some of the methane is used to run the treatment plant as fuel gas and other methane and heavier hydrocarbons, such as ethane, propane and butane, cannot be separated from the CO_2 and is lost. This is known as plant shrink. Historically our plant shrink has been approximately 14% in the WTO. After giving effect to plant shrink, as many as 4 Mcf of high CO_2 natural gas must be produced to sell one MMBtu of natural gas. We report our volumes of natural gas reserves and production net of CO_2 volumes that are removed prior to sales.

All of our consolidated drilling and services revenues are derived from companies in the oil and gas industry.

Companies to which we provide drilling and related services are affected by the oil and gas industry risks mentioned above. Market prices of natural gas and oil, limited access to capital and reductions in capital expenditures could result in oil and gas companies canceling or curtailing their drilling programs, which could reduce the demand for our drilling and related services. Any prolonged reduction in the overall level of exploration and development activities, whether resulting from changes in natural gas and oil prices or otherwise, could impact our drilling and services segment by negatively affecting:

- revenues, cash flow and profitability;
- our ability to retain skilled rig personnel whom we would need in the event of an upturn in the demand for drilling and related services; and
- the fair value of our rig fleet.

A significant decrease in natural gas production in our areas of operations, due to the decline in production from existing wells, depressed commodity prices or otherwise, would adversely affect our ability to satisfy certain contractual obligations and revenues and cash flow from our midstream gas services segment.

In June 2009, we sold an entity, Piñon Gathering Company, LLC ("PGC"), holding our gathering and compression assets located in the Piñon Field to an unaffiliated third party. In conjunction with the sale, we entered into a gas gathering agreement pursuant to which we dedicated our Piñon Field acreage to PGC for gathering services for 20 years. During that period, we have minimum throughput and delivery obligations to PGC. In addition, we continue to construct and acquire our own gathering and compression assets in the Piñon Field. Most of the reserves supporting our contractual obligations to PGC and our own midstream assets are operated by our exploration and production segment. A material decrease in natural gas production in our areas of operation would result in a decline in the volume of natural gas delivered to PGC's and our pipelines and facilities for gathering, transporting and treating. We have no control over many factors affecting production activity, including prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. Our throughput and delivery obligations to PGC may not be satisfied if we do not connect new wells to PGC's gathering systems or if there is a decline in natural gas that we produce from the Piñon Field; however, we would still be obligated to pay fees under the gas gathering agreement. Failure to connect new wells to our own gathering systems would result in the amount of natural gas we gather, transport and treat being reduced substantially over time and could, upon exhaustion of the current wells, cause us to abandon our gathering systems and, possibly cease gathering, transporting and treating operations.

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

A significant aspect of our exploration and development plan involves seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 2-D and 3-D seismic and other advanced technologies requires 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.

We often gather 2-D and 3-D seismic data over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 2-D and 3-D data without having an opportunity to attempt to benefit from those expenditures.

Drilling for and producing natural gas and 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 oil can be unprofitable if dry wells are drilled and if productive wells 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;
- blowouts;
- 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; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells 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 could incur losses 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.

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

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs of rigs, equipment, supplies and personnel are substantially greater and their availability may be limited. Additionally, these services may not be available on commercially reasonable terms.

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

Market conditions or a lack of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and 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 treating facilities. For example, we are currently experiencing capacity limitations on high CO_2 gas treating in the Piñon Field. Our failure to obtain such services on acceptable terms or expand our midstream assets could have a material adverse effect on our business. We may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering system capacity or treating facilities may be limited or unavailable. We would be unable to realize revenue from any shut-in wells until production arrangements were made to deliver the production to market.

Repercussions from terrorist activities or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts or other armed conflict involving the United States or its interests abroad may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If events of this nature occur and persist, the attendant political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on prevailing oil and natural gas prices and causing a reduction in our revenues. Oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and or operations could be adversely impacted if infrastructure integral to our operations is destroyed by such an attack. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our development and exploration operations 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 and oil reserves.

The natural gas and oil 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 and oil reserves. To date, we have financed capital expenditures primarily with proceeds from the sale of equity, debt and cash generated by operations. We intend to finance our future capital expenditures with the sale of equity and debt securities, cash flow from operations, asset sales and current and new financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of natural gas and oil we are able to produce from existing wells;

- the prices at which natural gas and oil are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas and oil 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. In order to fund our capital expenditures, we may seek additional financing. Our senior credit facility and senior note indentures, however, contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent at their sole discretion.

Continuing disruptions in the global financial and capital markets also could adversely affect our ability to obtain debt or equity financing on terms favorable to us, or at all. 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 and oil reserves.

The agreements governing our existing indebtedness have restrictions, financial covenants and borrowing base redeterminations which could adversely affect our operations.

Our senior credit facility and the indentures governing our senior notes restrict our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. If commodity prices remain at their current level for an extended period or continue to decline, this could adversely affect our ability to meet covenants. Our failure to comply with any of the restrictions and covenants under the senior credit facility, senior notes or other debt financing could result in a default under those instruments, which could cause all of our existing indebtedness to be immediately due and payable.

Our senior credit facility limits the amounts we can borrow to a borrowing base amount. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional re-determination of the borrowing base per calendar year. Unscheduled re-determinations may be made at our request, but are limited to two requests per year. The borrowing base is determined based upon proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other natural gas and oil properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments under the senior credit facility, which are required, for example, when we exceed our committed line of credit, fail to reinvest proceeds of asset sales in new natural gas and oil properties or incur indebtedness that is not permitted by the terms of the senior credit facility. If the indebtedness under our senior credit facility and senior notes were to be accelerated, our assets may not be sufficient to repay such indebtedness in full.

Our derivative activities could result in financial losses and could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas and oil, we currently, and may in the future, enter into derivative contracts for a portion of our natural gas and oil production, including collars, basis swaps and fixed-price swaps. As of December 31, 2009, we had natural gas price swaps of 80.3 Bcfe at an average price of $7.70 per Mcfe in place for 2010 and oil price swaps of 4,290 MBbls at an average price of $82.03 per MBbl for 2010, 4,745 MBbls at an average price of $86.52 per MBbl for 2011 and 4,392 MBbls at an average price of $88.26 per MBbl for 2012. The Company also has natural gas basis swaps in place through 2013 for 314.2 Bcf at an average price of $0.57 per Mcf. We have not designated any of our derivative contracts as hedges for accounting purposes and record all derivative contracts on our balance sheet at fair value. Changes in the fair value of our derivative contracts are recognized in current period earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative contracts. Derivative contracts also expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the derivative contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative contract and actual prices received.

In addition, these types of derivative contracts limit the benefit we would receive from increases in the prices for natural gas and oil.

Competition in the oil and gas industry is intense, which may adversely affect our ability to succeed.

The oil and gas industry is intensely competitive, and we compete with companies that have greater resources than we do. Many of these companies not only explore for and produce natural gas and oil, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties. See "Business — Competition" in Item 1 of this report.

Downturns in natural gas and oil prices can result in decreased oil field activity which, in turn, can result in an oversupply of service providers and drilling rigs. This oversupply can result in severe reductions in prices received for oil field services or a complete lack of work for crews and equipment.

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

Our natural gas and oil exploration, production, transportation and treatment 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 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. Such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental agencies and other bodies vested with authority relating to the exploration for, and the development, production and transportation of, natural gas and oil. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us. For instance, the MMS may suspend or terminate our operations on federal leases for failure to pay royalties or comply with safety and environmental regulations.

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 natural gas and oil exploration, development, production, transportation, treatment, and other activities. These costs and liabilities could arise under a wide range of environmental, health and safety laws 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 strict 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 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. Specifically, we may incur increased expenditures in the future in order to maintain compliance with laws and regulations governing emissions of air pollutants from our natural gas treatment plants. See "Business — Environmental Regulations" in Item 1 of this report.

Certain environmental laws impose strict joint and several liability that may require us to pay for or incur the costs to remediate contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not 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 such compliance could significantly and adversely affect our business, financial condition or results of operations. In addition, many countries as well as several states and regions of the United States have begun implementing legal measures to reduce emissions of greenhouse gases, including carbon dioxide and methane, a primary component of natural gas, in response to scientific studies suggesting that these gases may be contributing to the warming of the Earth's atmosphere. On the United States federal level, Congress is currently considering and President Obama has expressed support for legislation to restrict or regulate emissions of greenhouse gases. The EPA's Final Mandatory Reporting of Greenhouse Gases Rule, which requires reporting of certain greenhouse gas emissions, became effective December 29, 2009. Regulation of greenhouse gases could adversely impact some of our operations and demand for some of our services or products in the future. See "Business — Environmental Regulations" in Item 1 of this report.

The Century Plant may not be constructed, operate or perform as intended.

There are significant risks associated with the construction, operation and performance of a project such as the Century Plant. There are a limited number of firms and individuals with the expertise and experience necessary to complete construction projects of this size and nature. There is no assurance that the materials necessary for construction of the plant will be in ready supply when we need them or delivered to us on a timely basis. Accordingly, we may not be able to complete construction of the Century Plant within the time frame currently anticipated, and we could experience cost overruns that will not be covered by Occidental under our contract with Occidental. Finally, there is no guarantee that, once the Century Plant is constructed, we will be able to find, produce and deliver enough high CO_2 gas to satisfy our delivery obligations to Occidental or that the Century Plant will operate at its designed capacity or otherwise perform as anticipated.

We may not realize the anticipated benefits of past or future acquisitions, and integration of these acquisitions may disrupt our business and management.

We have in the past and may in the future acquire other companies or large asset packages. Most recently, we completed the Forest Acquisition in December 2009. We may not realize the anticipated benefits of an acquisition and each acquisition has numerous risks. These risks include:

- difficulty in assimilating the operations and personnel of the acquired company;
- difficulty in maintaining controls, procedures and policies during the transition and integration;
- disruption of our ongoing business and distraction of our management and employees from other opportunities and challenges;
- difficulty integrating the acquired company's accounting, management information, human resources and other administrative systems;
- inability to retain key personnel of the acquired business;
- inability to achieve the financial and strategic goals for the acquired and combined businesses;
- inability to take advantage of anticipated tax benefits;
- potential failure of the due diligence processes to identify significant problems, liabilities or other shortcomings or challenges of an acquired business;
- exposure to litigation or other claims in connection with, or inheritance of claims or litigation risk as a result of, an acquisition, including but not limited to, claims from terminated employees, customers, former stockholders or other third-parties;
- potential inability to assert that internal controls over financial reporting are effective; and
- potential incompatibility of business cultures.

If we fail to maintain an adequate system of internal control over financial reporting, it could adversely affect our ability to accurately report our results.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in our internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for us to provide reliable financial reports and effectively prevent material fraud. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, or other effective improvement of our internal controls could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama's Proposed Fiscal Year 2011 Budget included proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect our financial condition and results of operations.

The adoption of new derivatives legislation or regulation could adversely affect our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. The Wall Street Reform and Consumer Protection Act of 2009, which was approved by the U.S. House of Representatives on December 11, 2009, would subject over-the-counter ("OTC") derivative dealers and major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strict business conduct standards. Derivative contracts that are not cleared through central clearinghouses or exchanges may be subject to substantially higher capital and margin requirements. In addition, the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA, which was approved by the U.S. House of Representatives on June 26, 2009, contains provisions that would prohibit private OTC energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission (the "CFTC") to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC's expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. On January 14, 2010, the CFTC proposed rules to establish position limits on derivatives that reference major energy commodities, including natural gas and oil. The proposed all-months-combined position limits would be 10% of the first 25,000 contracts of open interest and 2.5% of open interest beyond 25,000 contracts. The CFTC's proposal includes an exemption for *bona fide* hedges relating to inventory or anticipatory purchases or sales of the commodity. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. Although it is not possible at this time to predict the specific content of any derivatives legislation that may ultimately be enacted, any such laws or regulations that are adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

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 gas industry in the hydraulic fracturing process and impose additional regulatory burdens on our industry. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives 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 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.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the gas and oil that we produce.

On December 7, 2009, the EPA announced its findings that emissions of carbon dioxide, methane and other greenhouse gases endanger human health and the environment because emissions of such gases, according to the EPA, contribute to warming the Earth's atmosphere and other climate changes. These findings by the EPA allow it to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In September 2009, the EPA proposed two sets of regulations in anticipation of finalizing its findings. The proposed regulations would require a reduction in emissions of greenhouse gases from motor vehicles and also could require permits for emitting greenhouse gas from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring annual reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the gas and oil we produce.

Also, on June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009," (the "ACESA") which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane, that may contribute to warming of the Earth's atmosphere and other climate changes. The ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases. The net effect of the ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and natural gas. The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and President Obama has indicated his support of legislation to reduce greenhouse gas emissions through an emission allowance system. Although it is not possible at this time to predict whether or when the United States Senate may act on this or other climate change legislation or how any bill passed by the United States Senate would be reconciled with the ACESA, any federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the gas and oil we produce.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

Information regarding our properties is included in Item 1 and in Notes 6 and 25 of the notes to our consolidated financial statements included in Item 8 of this report.

Item 3. *Legal Proceedings*

SandRidge is a defendant in lawsuits from time to time in the normal course of business. In management's opinion, we are not currently involved in any legal proceedings that, individually or in the aggregate, could have a material effect on our financial condition, operations or cash flows.

Item 4. *Reserved*

PART II

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

Price Range of Common Stock

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "SD." The range of high and low sales prices for our common stock for the periods indicated, as reported by the NYSE, is as follows:

	High	Low
2009		
Fourth Quarter	$14.08	$ 7.97
Third Quarter	$15.00	$ 7.44
Second Quarter	$11.84	$ 6.31
First Quarter	$ 8.79	$ 4.49
2008		
Fourth Quarter	$19.54	$ 4.85
Third Quarter	$69.41	$17.46
Second Quarter	$69.00	$37.88
First Quarter	$41.05	$28.50

On February 19, 2010, there were 228 record holders of our common stock.

We have neither declared nor paid any cash dividends on our common stock, and we do not anticipate declaring any dividends on our common stock in the foreseeable future. We expect to retain our cash for the operation and expansion of our business, including exploration, development and production activities. In addition, the terms of our indebtedness restrict our ability to pay dividends to holders of our common stock. Accordingly, if our dividend policy were to change in the future, our ability to pay dividends would be subject to these restrictions and our then-existing conditions, including our results of operations, financial condition, contractual obligations, capital requirements, business prospects and other factors deemed relevant by our board of directors.

Issuer Purchases of Equity Securities

As part of our incentive compensation program, we make required tax payments on behalf of employees as their restricted stock awards vest and then withhold a number of vested shares having a value on the date of vesting equal to the tax obligation. The shares withheld are recorded as treasury stock. During the quarter ended December 31, 2009, the following shares of common stock were withheld in satisfaction of tax withholding obligations arising from the vesting of restricted stock:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2009 — October 31, 2009	29,643	$13.04	N/A	N/A
November 1, 2009 — November 30, 2009	1,273	$ 9.38	N/A	N/A
December 1, 2009 — December 31, 2009	—	—	N/A	N/A

Item 6. *Selected Financial Data*

The following table sets forth, as of the dates and for the periods indicated, our selected financial information. Our financial information is derived from our audited consolidated financial statements for such periods. The financial data includes the results of the Forest Acquisition, effective December 21, 2009, and the acquisition of NEG Oil & Gas, LLC ("NEG"), effective November 21, 2006. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report and our consolidated financial statements and notes thereto contained in Item 8 of this report. The following information is not necessarily indicative of our future results.

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues	$ 591,044	$ 1,181,814	$ 677,452	$388,242	$287,693
Expenses:					
Production	169,285	159,004	106,192	35,149	16,195
Production taxes	4,010	30,594	19,557	4,654	3,158
Drilling and services	30,899	26,186	44,211	98,436	52,122
Midstream and marketing	78,684	186,655	94,253	115,076	141,372
Depreciation and depletion — natural gas and oil	176,027	290,917	173,568	26,321	9,313
Depreciation, depletion and amortization — other	50,865	70,448	53,541	29,305	14,893
Impairment	1,707,150	1,867,497	—	—	—
General and administrative	100,256	109,372	61,780	55,634	11,908
(Gain) loss on derivative contracts	(147,527)	(211,439)	(60,732)	(12,291)	4,132
Loss (gain) on sale of assets	26,419	(9,273)	(1,777)	(1,023)	547
Total operating expenses	2,196,068	2,519,961	490,593	351,261	253,640
(Loss) income from operations	(1,605,024)	(1,338,147)	186,859	36,981	34,053
Other income (expense):					
Interest income	375	3,569	4,694	991	206
Interest expense	(185,691)	(147,027)	(117,185)	(16,904)	(5,277)
Income (loss) from equity investments	1,020	1,398	4,372	967	(384)
Other income, net	7,272	1,454	729	118	—
Total other (expense) income	(177,024)	(140,606)	(107,390)	(14,828)	(5,455)
(Loss) income before income taxes	(1,782,048)	(1,478,753)	79,469	22,153	28,598
Income tax (benefit) expense	(8,716)	(38,328)	29,524	6,236	9,968
(Loss) income from continuing operations	(1,773,332)	(1,440,425)	49,945	15,917	18,630
Income from discontinued operations, net of tax	—	—	—	—	229
Net (loss) income	(1,773,332)	(1,440,425)	49,945	15,917	18,859
Less: net income (loss) attributable to noncontrolling interest	2,258	855	(276)	296	737
Net (loss) income attributable to SandRidge Energy, Inc	(1,775,590)	(1,441,280)	50,221	15,621	18,122
Preferred stock dividends and accretion	8,813	16,232	39,888	3,967	—
(Loss applicable) income available to SandRidge Energy, Inc., common stockholders	$(1,784,403)	$(1,457,512)	$ 10,333	$ 11,654	$ 18,122
Earnings Per Share Information:					
Basic and Diluted					
Net (loss) income attributable to SandRidge Energy, Inc.	$ (10.15)	$ (9.26)	$ 0.46	$ 0.21	$ 0.31
Income from discontinued operations, net of income tax	—	—	—	—	0.01
Preferred stock dividends	(0.05)	(0.10)	(0.37)	(0.05)	—
(Loss) income per share (applicable) available to SandRidge Energy, Inc., common stockholders	$ (10.20)	$ (9.36)	$ 0.09	$ 0.16	$ 0.32
Weighted average number of SandRidge Energy, Inc., common shares outstanding(1):					
Basic	175,005	155,619	108,828	73,727	56,559
Diluted	175,005	155,619	110,041	74,664	56,737

(1) The number of shares has been adjusted to reflect a 281.562-to-1 stock split in December 2005.

	As of December 31,				
	2009	2008	2007	2006	2005
			(In thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 7,861	$ 636	$ 63,135	$ 38,948	$ 45,731
Property, plant and equipment, net	$2,433,643	$3,175,559	$3,337,410	$2,134,718	$337,881
Total assets	$2,780,317	$3,655,058	$3,630,566	$2,388,384	$458,683
Long-term debt	$2,578,938	$2,375,316	$1,067,649	$1,066,831	$ 43,133
Redeemable convertible preferred stock(1)	$ —	$ —	$ 450,715	$ 439,643	$ —
Total (deficit) equity	$ (195,905)	$ 793,551	$1,771,563	$ 654,910	$297,179
Total liabilities and equity	$2,780,317	$3,655,058	$3,630,566	$2,388,384	$458,683

(1) On May 7, 2008, we converted all of our then outstanding redeemable convertible preferred stock into shares of our common stock.

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

Introduction

The following discussion and analysis is intended to help the reader understand our business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis is provided as a supplement to, and should be read in conjunction with, the other sections of this report, including: "Business" in Item 1, "Selected Financial Data" in Item 6 and "Financial Statements and Supplementary Data" in Item 8. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this report, particularly in "Risk Factors" in Item 1A of this report and "Cautionary Statement Concerning Forward-Looking Statements" below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview of Our Company

We are an independent natural gas and oil company concentrating on exploration, development and production activities related to the exploitation of our significant holdings in West Texas. Our primary areas of focus are the WTO and the Permian Basin. The WTO is a natural gas-prone geological region where we have operated since 1986. The WTO includes the Piñon gas field. We completed numerous acquisitions of additional working interests in the WTO during 2007 and 2008. Additionally, we focus on the exploration, development and production of our properties in the Permian Basin including properties recently acquired from Forest, as discussed below. We also operate interests in the Mid-Continent, the Cotton Valley Trend in East Texas, the Gulf Coast and the Gulf of Mexico.

We currently generate the majority of our consolidated revenues and cash flow from the production and sale of natural gas and oil. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and oil and on our ability to find and economically develop and produce natural gas and oil reserves. Prices for natural gas and oil fluctuate widely. In order to reduce our exposure to these fluctuations, we enter into derivative commodity contracts for a portion of our anticipated future natural gas and oil production. Reducing our exposure to price volatility helps ensure that we have adequate funds available for our capital expenditure programs.

We operate businesses that are complementary to our exploration, development and production activities. We own related gas gathering and treating facilities, a gas marketing business and an oil field services business. The extent to which each of these supplemental businesses contributes to our consolidated results of operations largely is determined by the amount of work each performs for third parties. Revenues and costs related to work performed by these businesses for our own account are eliminated in consolidation and, therefore, do not contribute to our consolidated results of operations.

Recent Developments

Forest Acquisition. In December 2009, we purchased natural gas and oil properties located in the Permian Basin from Forest for $800.0 million, subject to purchase price and post-closing adjustments. For more information about the Forest Acquisition, see Item 1, Business — Recent Developments.

Common Stock Offering. In December 2009, we completed a registered underwritten public offering of 25,600,000 shares of our common stock, including 3,600,000 shares of common stock acquired by the underwriters from us to cover over-allotments. Net proceeds from the offering were approximately $217.2 million after deducting offering expenses of approximately $9.4 million. The net proceeds were used to fund a portion of the Forest Acquisition purchase price and for general corporate purposes.

8.75% Senior Notes Due 2020. In December 2009, we completed the sale of $450.0 million of our unsecured 8.75% Senior Notes to qualified institutional buyers eligible under Rule 144A of the Securities Act. Net proceeds from the offering were approximately $433.1 million after the issuance discount and deducting offering expenses of approximately $9.5 million. We used such proceeds to fund a portion of the Forest Acquisition purchase price.

Private Placement of 6.0% Convertible Perpetual Preferred Stock. In December 2009, we completed a private placement of 2,000,000 shares of our 6.0% convertible perpetual preferred stock to an institutional investor in a transaction exempt from registration under Regulation D under the Securities Act. Net proceeds were approximately $199.9 million and were used to fund a portion of the Forest Acquisition purchase price and for general corporate purposes.

Each share of the 6.0% convertible perpetual preferred stock has a liquidation preference of $100.00 and is entitled to an annual dividend of $6.00 payable semi-annually in cash, common stock or any combination thereof, beginning on July 15, 2010. Additionally, each share is initially convertible into 9.21 shares of our common stock, at the holder's option, at any time on or after February 1, 2010 based on an initial conversion price of $10.86 and subject to customary adjustments in certain circumstances. Five years after their issuance, all outstanding shares of the convertible preferred stock will be converted automatically into shares of our common stock at the then-prevailing conversion price as long as all dividends accrued at that time have been paid.

2010 Capital Expenditure Budget. On February 25, 2010, we introduced 2010 production guidance of 130 Bcfe based on 2010 capital expenditure guidance of $860.0 million.

Crusader Acquisition Bid Withdrawal. In September 2009, we entered into the Crusader Purchase Agreement to purchase all of the shares of common stock of Crusader that were to be issued upon the effectiveness of Crusader's reorganization under Chapter 11 of the United States Bankruptcy Code. On November 12, 2009, we announced our withdrawal from the acquisition process of Crusader as permitted under the bidding procedures applicable to Crusader's bankruptcy. On December 14, 2009, we terminated the Crusader Purchase Agreement and on December 31, 2009, we received the break-up fee of $7.0 million provided for in the Crusader Purchase Agreement.

Results by Segment

We operate in three business segments: exploration and production, drilling and oil field services and midstream gas services. The All Other column in the tables below includes items not related to our reportable segments such as our CO_2 gathering and sales operations and corporate operations. Management evaluates the performance of our business segments based on operating income (loss), which is defined as segment operating revenues less operating expenses. Results of these measurements provide important information to us about the activity and profitability of our lines of business. Set forth in the table below is financial information regarding each of our business segments for the years ended December 31, 2009, 2008 and 2007 (in thousands).

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2009					
Revenues	$ 457,397	$ 225,227	$ 299,580	$ 30,654	$ 1,012,858
Inter-segment revenue	(261)	(201,641)	(215,667)	(4,245)	(421,814)
Total revenues	$ 457,136	$ 23,586	$ 83,913	$ 26,409	$ 591,044
Operating loss(1)	$(1,488,078)	$ (15,166)	$ (36,989)	$(64,791)	$(1,605,024)
Interest expense, net	(180,856)	(2,074)	(1,246)	(1,140)	(185,316)
Other income, net	4,673	—	3,365	254	8,292
Loss before income taxes	$(1,664,261)	$ (17,240)	$ (34,870)	$(65,677)	$(1,782,048)
Capital expenditures(2)	$ 555,809	$ 4,090	$ 52,425	$ 32,818	$ 645,142
Depreciation, depletion and amortization	$ 178,783	$ 28,221	$ 5,496	$ 14,392	$ 226,892
Year Ended December 31, 2008					
Revenues	$ 912,716	$ 434,963	$ 688,071	$ 22,791	$ 2,058,541
Inter-segment revenue	(220)	(387,972)	(483,933)	(4,602)	(876,727)
Total revenues	$ 912,496	$ 46,991	$ 204,138	$ 18,189	$ 1,181,814
Operating (loss) income(1)	$(1,263,249)	$ (5,393)	$ 2,087	$(71,592)	$(1,338,147)
Interest expense, net	(139,494)	(2,766)	—	(1,198)	(143,458)
Other income, net	1,171	1,015	398	268	2,852
(Loss) income before income taxes	$(1,401,572)	$ (7,144)	$ 2,485	$(72,522)	$(1,478,753)
Capital expenditures(2)	$ 1,909,078	$ 52,869	$ 160,460	$ 55,440	$ 2,177,847
Depreciation, depletion and amortization	$ 293,625	$ 42,077	$ 15,241	$ 10,422	$ 361,365
Year Ended December 31, 2007					
Revenues	$ 479,321	$ 261,818	$ 285,065	$ 29,286	$ 1,055,490
Inter-segment revenue	(574)	(188,616)	(177,487)	(11,361)	(378,038)
Total revenues	$ 478,747	$ 73,202	$ 107,578	$ 17,925	$ 677,452
Operating income (loss)	$ 198,913	$ 10,473	$ 6,783	$(29,310)	$ 186,859
Interest expense, net	(109,458)	(2,762)	(165)	(106)	(112,491)
Other income, net	713	2,391	1,981	16	5,101
Income (loss) before income taxes	$ 90,168	$ 10,102	$ 8,599	$(29,400)	$ 79,469
Capital expenditures(2)	$ 1,046,552	$ 123,232	$ 63,828	$ 47,236	$ 1,280,848
Depreciation, depletion and amortization	$ 175,565	$ 37,792	$ 6,641	$ 7,111	$ 227,109

(1) The operating loss for the exploration and production segment for the years ended December 31, 2009 and 2008 includes non-cash full cost ceiling impairments of $1,693.3 million and $1,855.0 million, respectively, on our natural gas and oil properties. The operating loss for the midstream gas services segment for the year ended December 31, 2009 includes a $26.1 million loss on the sale of our gathering and compression assets in the Piñon Field.

(2) On an accrual basis.

Exploration and Production Segment

The primary factors affecting the financial results of our exploration and production segment are the prices we receive for our natural gas and oil production, the quantity of natural gas and oil we produce and changes in the fair value of commodity derivative contracts we use to reduce the volatility of the prices we receive for our natural gas and oil production. Annual comparisons of production and price data are presented in the following tables.

	Year Ended December 31,		Change	
	2009	**2008**	**Amount**	**Percent**
Production data:				
Natural gas (MMcf)	87,461	87,402	59	0.1%
Oil (MBbls)	2,894	2,334	560	24.0%
Combined equivalent volumes (MMcfe)	104,823	101,405	3,418	3.4%
Average daily combined equivalent volumes (MMcfe/d)	287.2	277.1	10.1	3.6%
Average prices — as reported(1):				
Natural gas (per Mcf)	$ 3.36	$ 7.95	$ (4.59)	(57.7)%
Oil (per Bbl)(2)	$ 55.62	$ 91.54	$ (35.92)	(39.2)%
Combined equivalent (per Mcfe)	$ 4.34	$ 8.96	$ (4.62)	(51.6)%
Average prices — including impact of derivative contract settlements:				
Natural gas (per Mcf)	$ 7.20	$ 7.90	$ (0.70)	(8.9)%
Oil (per Bbl)(2)	$ 59.69	$ 88.09	$ (28.40)	(32.2)%
Combined equivalent (per Mcfe)	$ 7.66	$ 8.83	$ (1.17)	(13.3)%

	Year Ended December 31,		Change	
	2008	**2007**	**Amount**	**Percent**
Production data:				
Natural gas (MMcf)	87,402	51,958	35,444	68.2%
Oil (MBbls)	2,334	2,042	292	14.3%
Combined equivalent volumes (MMcfe)	101,405	64,211	37,194	57.9%
Average daily combined equivalent volumes (MMcfe/d)	277.1	175.9	101.2	57.5%
Average prices — as reported(1):				
Natural gas (per Mcf)	$ 7.95	$ 6.51	$ 1.44	22.1%
Oil (per Bbl)(2)	$ 91.54	$ 68.12	$ 23.42	34.4%
Combined equivalent (per Mcfe)	$ 8.96	$ 7.45	$ 1.51	20.3%
Average prices — including impact of derivative contract settlements:				
Natural gas (per Mcf)	$ 7.90	$ 7.18	$ 0.72	10.0%
Oil (per Bbl)(2)	$ 88.09	$ 68.10	$ 19.99	29.4%
Combined equivalent (per Mcfe)	$ 8.83	$ 7.98	$ 0.85	10.7%

(1) Prices represent actual average prices for the periods presented and do not give effect to derivative transactions.

(2) Includes natural gas liquids.

As of December 31, 2009, we had 1,312.2 Bcfe of estimated net proved reserves with a PV-10 of $1,561.0 million, compared to 2,158.6 Bcfe of estimated net proved reserves with a PV-10 of $2,258.5 million as of December 31, 2008. Our Standardized Measure was $1,561.0 million at December 31, 2009 compared to $2,220.6 million at December 31, 2008 and $2,718.5 million at December 31, 2007. For a discussion of PV-10 and reconciliation to Standardized Measure, see "Business — Our Business and Primary Operations — Proved Reserves" in Item 1 of this report. The decrease in PV-10 in 2009 is primarily attributable to lower commodity prices used in the determination of estimated net proved reserves at December 31, 2009 compared to December 31, 2008. Under SEC rules that became effective December 31, 2009, natural gas and oil reserves are calculated based on the average price during the 12-month period, using the first-day-of-the-month price for each month in the period instead of the one-day period end pricing method previously used. For the 12-month period ended December 31, 2009, the prices used in our external and internal reserve reports yield weighted average wellhead prices of $3.41 per Mcf of natural gas and $49.98 per barrel of oil based on index prices used ($3.87 per Mcf of natural gas and $57.65 per barrel of oil at December 31, 2009). The SEC requires public companies utilizing the full cost method of accounting for oil and gas properties to perform a ceiling limitation calculation at the end of each quarterly and annual reporting period. As a result of lower natural gas and oil prices during 2009, which were used to determine the future value of our reserves, we were required to record a ceiling impairment of $388.9 million at December 31, 2009, in addition to the $1,304.4 million ceiling impairment recorded at March 31, 2009.

Exploration and Production Segment — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Exploration and production segment revenues decreased 49.9% to $457.1 million for the year ended December 31, 2009 from $912.5 million in 2008, as a result of a 51.6% decrease in the average price we received for the natural gas and oil we produced, offset slightly by a 3.4% increase in combined production volumes. During 2009, we increased natural gas production slightly by 59 MMcf to 87.5 Bcf and increased oil production by 560 MBbls to 2,894 MBbls. The total combined 3.4 Bcfe increase in production is primarily due to the increased oil production resulting from new wells in West Texas and the Permian Basin.

The average price we received for our natural gas production for the year ended December 31, 2009 decreased $4.59 per Mcf, or 57.7%, to $3.36 per Mcf from $7.95 per Mcf in 2008. The average price received for our oil production decreased to $55.62 per Bbl from $91.54 per Bbl in 2008. The average price we received for our natural gas and oil production was negatively impacted by the continued decline in natural gas and oil prices experienced by the industry during 2009. Including the impact of derivative contract settlements, the effective average price received for natural gas for the year ended December 31, 2009 was $7.20 per Mcf compared to $7.90 per Mcf during 2008. Our oil derivative contract settlements increased our effective price received for oil by $4.07 per Bbl to $59.69 per Bbl for the year ended December 31, 2009. Our oil derivative contract settlements decreased our effective price received for oil by $3.45 per Bbl to $88.09 per Bbl for the year ended December 31, 2008. During 2008 and 2009, we entered into derivative contracts to mitigate the impact of commodity price fluctuations on our production through 2013. Due to the long-term nature of our investment in the development of our properties, we enter into natural gas and oil swaps and natural gas basis swaps for a portion of our production in order to stabilize future cash inflows for planning purposes. Our derivative contracts are not designated as hedges and, as a result, gains or losses on commodity derivative contracts are recorded as a component of operating expenses. Internally, management views the settlement of such derivative contracts as adjustments to the price received for natural gas and oil production to determine "effective prices."

During the year ended December 31, 2009, the exploration and production segment reported a $147.5 million net gain on our commodity derivative contracts ($348.0 million realized gain and $200.5 million unrealized loss) compared to a $211.4 million net gain ($13.0 million realized losses and $224.4 million unrealized gain) in 2008. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative contracts during the period. The unrealized loss on natural gas and oil derivative contracts recorded during the year ended December 31, 2009 is attributable to an increase in average natural gas and oil prices at December 31, 2009 compared to the average natural gas and oil prices at December 31, 2008 or the contract price for contracts entered into during 2009. The realized gain of $348.0 million for the year ended December 31, 2009 is primarily due to a decline in natural gas prices at the time of settlement compared to the contract price.

For the year ended December 31, 2009, we had an operating loss of $1,488.1 million in our exploration and production segment, compared to an operating loss of $1,263.2 million in 2008. The operating loss for the year ended December 31, 2009 is attributable to the $455.4 million decrease in exploration and production segment revenues and full cost ceiling impairments totaling $1,693.3 million, partially offset by $147.5 million in net gain on our commodity derivative contracts and a $114.9 million decrease in depreciation and depletion on natural gas and oil properties due to the decrease in the average depreciation and depletion per Mcfe. The full cost ceiling impairments are the result of the decline of the future value of our reserves based on the natural gas and oil prices at March 31, 2009 and the 12-month average prices at December 31, 2009.

Exploration and Production Segment — Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

For the year ended December 31, 2008, exploration and production segment revenues increased to $912.5 million from $478.7 million in 2007. The increase in 2008 revenues compared to 2007 was attributable to increased production primarily due to successful drilling activity in the WTO and an increase in the average price received for the natural gas and oil we produced. Production volumes increased to 101.4 Bcfe in 2008 from 64.2 Bcfe in 2007, representing an increase of 37.2 Bcfe, or 57.9%. Average combined prices increased $1.51, or 20.3%, to $8.96 per Mcfe in 2008 compared to $7.45 per Mcfe in 2007.

The average price we received for our natural gas production for the year ended December 31, 2008 increased $1.44 per Mcf, or 22.1%, to $7.95 per Mcf from $6.51 per Mcf in 2007. The average price received for our oil production increased to $91.54 per Bbl from $68.12 per Bbl in 2007. The average price we received for our natural gas and oil production was negatively impacted by the significant decline in natural gas and oil prices experienced by the oil and gas industry in the fourth quarter of 2008. The average price received for our natural gas and oil production during the first nine months of 2008 was $9.09 per Mcf and $104.73 per Bbl, respectively, compared to the average price received for our natural gas and oil production during the fourth quarter of 2008 of $5.01 per Mcf and $51.92 per Bbl, respectively. Including the impact of derivative contract settlements, the effective average price received for natural gas for the year ended December 31, 2008 was $7.90 per Mcf compared to $7.18 per Mcf during 2007. Our oil derivative contract settlements decreased our effective price received for oil by $3.45 per Bbl to $88.09 per Bbl for the year ended December 31, 2008. For the year ended December 31, 2007, our oil derivative contract settlements had a minimal impact on our effective price received for oil, which was $68.10 per Bbl.

During the year ended December 31, 2008, the exploration and production segment reported a $211.4 million net gain on our commodity derivative contracts ($13.0 million realized loss and $224.4 million unrealized gain) compared to a $60.7 million net gain ($34.5 million realized gain and $26.2 million unrealized gain) in 2007. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative contracts during the period. The unrealized gain on natural gas and oil derivative contracts recorded during the year ended December 31, 2008 was attributable to a decrease in average natural gas and oil prices at December 31, 2008 compared to the average natural gas and oil prices at December 31, 2007 or the contract price for contracts entered into during 2008.

For the year ended December 31, 2008, we had an operating loss of $1,263.2 million in our exploration and production segment compared to operating income of $198.9 million in 2007. The $433.8 million increase in exploration and production segment revenues and a $211.4 million net gain on our commodity derivative contracts, of which $224.4 million was unrealized, were offset by a full cost ceiling impairment of $1,855.0 million, a $52.8 million increase in production expenses and a $117.3 million increase in depreciation and depletion on natural gas and oil properties due to the increase in production. The 2008 full cost ceiling impairment was the result of the decline of the future value of our reserves due to the natural gas and oil prices at December 31, 2008 which offset the increase in overall estimated reserve quantities assigned to our properties. There was no ceiling impairment at December 31, 2007. See further discussion of production expense and depreciation and depletion — natural gas and oil properties at "Results of Operations — Consolidated."

Drilling and Oil Field Services Segment

The financial results of our drilling and oil field services segment depend primarily on the demand for and price we can charge for our services. In addition to providing drilling services, our oil field services business also conducts operations that complement our drilling services such as providing pulling units, trucking, rental tools, location and road construction and roustabout services. On a consolidated basis, drilling and oil field service revenues earned and expenses incurred on performing services for third parties, including third party working interests in wells we operate, are included in drilling and services revenues and expenses while drilling and oil field service revenues earned and expenses incurred in performing services for our own account are eliminated in consolidation.

As of December 31, 2009, we owned 31 drilling rigs, through Lariat, of which 14 were idle and one was non-operational. As Lariat's rigs are intended primarily to drill for our account, there is not a significant impact to our consolidated results of operations in having this number of rigs idle.

The table below presents information concerning rigs owned by Lariat:

	December 31,	
	2009	2008
Rigs working for SandRidge	14	13
Rigs working for third parties	2	3
Idle rigs	14	12
Total operational	30	28
Non-operational rigs	1	3
Total rigs owned	31	31

Until April 15, 2009, we indirectly owned, through Lariat and its partner Clayton Williams Energy, Inc. ("CWEI"), an additional 11 operational rigs through an investment in Larclay L.P. ("Larclay"). Although our ownership in Larclay afforded us access to Larclay's operational rigs, we did not control Larclay, and, therefore, did not consolidate the results of its operations with ours. Only the activities of our wholly owned drilling and oil field services subsidiaries are included in the financial results of our drilling and oil field services segment. On April 15, 2009, Lariat completed an assignment to CWEI of Lariat's 50% equity interest in Larclay pursuant to the terms of an Assignment and Assumption Agreement (the "Larclay Assignment") entered into between Lariat and CWEI. Pursuant to the Larclay Assignment, Lariat assigned all of its right, title and interest in and to Larclay to CWEI effective as of April 15, 2009, and CWEI assumed all of the obligations and liabilities of Lariat relating to Larclay. We fully impaired our investment in and notes receivable due from Larclay at December 31, 2008. There were no additional losses on Larclay during the year ended December 31, 2009 or as a result of the Larclay Assignment.

Drilling and Oil Field Services Segment — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Drilling and oil field services segment revenues decreased to $23.6 million for the year ended December 31, 2009 from $47.0 million for the year ended December 31, 2008. This resulted in an operating loss of $15.2 million during 2009 compared to an operating loss of $5.4 million during 2008. The decline in revenues and operating income is primarily attributable to a decrease in the number of our rigs operating and decreases in services performed for third parties as well as lower operating margins during 2009 compared to 2008. During 2009, an average of 8.3 of the 30 operational rigs we owned were working compared to an average of 25.5 of the 28 operational rigs working during 2008. Additionally, the average daily rate received per rig working for third parties declined to an average of $11,398 per rig per working day during 2009 from an average of $14,217 per rig per working day during 2008. We received reduced, or stand-by rates, on two of our rigs during 2009 which resulted in a lower average rate per rig per working day for the year ended December 31, 2009 than the comparable period in 2008.

Drilling and Oil Field Services Segment — Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

During 2008, our drilling and oil field services segment reported $47.0 million in revenues, a decrease of $26.2 million, or 35.8%, from 2007. For the year ended December 31, 2008, we had an operating loss of $5.4 million compared to operating income of $10.5 million in 2007. The decline in revenues and operating income is primarily attributable to an increase in the number of rigs operating on our properties, an increase in our ownership interest in our natural gas and oil properties, resulting in decreases in services performed for third parties, and a decline in revenue earned per day by rigs working for third parties during 2008 compared to 2007. During the year ended December 31, 2008, 89.2% of drilling and oil field service segment revenues were generated by work performed on our own account and eliminated in consolidation compared to 72.0% in 2007.

Midstream Gas Services Segment

Midstream gas services segment revenues consist mostly of revenue from gas marketing, which is a very low-margin business. On a consolidated basis, midstream and marketing revenues represent natural gas sold on behalf of third parties and the fees we charge related to gathering, compressing and treating this gas. Gas marketing operating costs represent payments made to third parties for the proceeds from the sale of gas owned by such parties, net of any applicable margin and actual costs to gather, compress and treat the gas that we charge. The primary factors affecting midstream gas services are the quantity of natural gas we gather, treat and market and the prices we pay and receive for natural gas.

In June 2009, we completed the sale of our gathering and compression assets located in the Piñon Field of the WTO. Net proceeds from the sale were approximately $197.5 million, which resulted in a loss on the sale of $26.1 million. The sale of these assets did not and is not expected to have a significant impact on our future consolidated results of operations. In conjunction with the sale, we entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, we have dedicated our Piñon Field acreage for priority gathering services for a period of 20 years and we will pay a fee for such services that was negotiated at arms' length. Pursuant to the operations and maintenance agreement, we will operate and maintain the gathering system assets sold for a period of 20 years unless we or the buyer of the assets chooses to terminate the agreement.

Grey Ranch, L.P. ("GRLP") is a limited partnership that operates the Grey Ranch Plant located in Pecos County, Texas. We purchased our investment in GRLP during 2003. During October 2009, we executed amendments to certain agreements related to the ownership and operation of GRLP. As a result of these amendments, we became the primary beneficiary of GRLP. Due to this change, we began consolidating the activity of GRLP in our midstream gas services segment prospectively beginning on the effective date of the amendments, October 1, 2009.

Midstream Gas Services Segment — Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Midstream gas services segment revenues for the year ended December 31, 2009 were $83.9 million compared to $204.1 million in 2008. The decrease in midstream gas services revenues is attributable to an overall decrease in natural gas prices in 2009 compared to 2008. Operating costs decreased in proportion to revenue based on the decrease in natural gas prices paid in 2009 compared to 2008. Profit margin for 2009 was 6.2% compared to a profit margin of 8.6% for 2008. The operating loss of $37.0 million for 2009 compared to operating income of $2.1 million in 2008 is primarily attributable to the loss on the sale of our gathering and compression assets. Also contributing to the loss was the impairment of spare parts inventory recorded in 2009.

Midstream Gas Services Segment — Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Midstream gas services segment revenues increased $96.5 million to $204.1 million for the year ended December 31, 2008 from $107.6 million in 2007. The increase in midstream gas services revenues is attributable to larger third-party volumes transported and marketed through our gathering systems during 2008 compared to 2007 as well as an overall increase in natural gas prices in 2008 compared to 2007. Operating income generated by our midstream gas services segment decreased $4.7 million in 2008 to $2.1 million from $6.8 million in 2007 due to an increase in depreciation expense attributable to higher carrying values of midstream gathering and treating assets.

Consolidated Results of Operations

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Revenues. Total revenues decreased 50.0% to $591.0 million for the year ended December 31, 2009 from $1,181.8 million in 2008. This decrease is primarily due to a $454.0 million decrease in natural gas and oil sales and a $121.6 million decrease in midstream and marketing revenues.

	Year Ended December 31, 2009	Year Ended December 31, 2008	$ Change	% Change
		(In thousands)		
Revenues:				
Natural gas and oil	$454,705	$ 908,689	$(453,984)	(50.0)%
Drilling and services	23,902	47,199	(23,297)	(49.4)%
Midstream and marketing	86,028	207,602	(121,574)	(58.6)%
Other	26,409	18,324	8,085	44.1%
Total revenues	$591,044	$1,181,814	$(590,770)	(50.0)%

Total natural gas and oil revenues decreased $454.0 million to $454.7 million for the year ended December 31, 2009, compared to $908.7 million in 2008, primarily as a result of the decrease in natural gas and oil prices received on our production. The average price received, excluding the impact of derivative contracts, for our natural gas and oil production decreased 51.6% in 2009 to a combined equivalent price of $4.34 per Mcfe compared to $8.96 per Mcfe in 2008. The average price we received for our natural gas and oil production was negatively impacted by the decline in natural gas and oil prices experienced by the oil and gas industry during 2009. Total natural gas production increased 0.1% to 87.5 Bcf in 2009 compared to 87.4 Bcf in 2008, while oil production increased 24.0% to 2,894 MBbls in 2009 from 2,334 MBbls in 2008.

Drilling and services revenues decreased 49.4% to $23.9 million in 2009 compared to $47.2 million in 2008. The decline in revenues is due to a decrease in rigs operating for and services performed for third parties and the decline in the average daily rate received per rig working for third parties. The average daily rate we received per rig working for third parties declined to an average of $11,398 per rig per working day during 2009 from an average of $14,217 per rig per working day during 2008.

Midstream and marketing revenues decreased $121.6 million, or 58.6%, to $86.0 million for the year ended December 31, 2009, compared to $207.6 million in 2008. The decrease is attributable to the decrease in prices for natural gas that we sold on behalf of third parties in 2009 compared to 2008.

Other revenues increased to $26.4 million for the year ended December 31, 2009 from $18.3 million for 2008. The increase is primarily due to higher CO_2 volumes sold to third parties during 2009 than 2008.

Operating Costs and Expenses. Total operating costs and expenses decreased to $2,196.1 million during 2009, compared to $2,520.0 million in 2008, primarily as a result of decreases in our midstream and marketing expenses, depreciation and depletion and the full cost ceiling impairment.

	Year Ended December 31, 2009	Year Ended December 31, 2008	$ Change	% Change
	(In thousands)			
Operating costs and expenses:				
Production	$ 169,285	$ 159,004	$ 10,281	6.5%
Production taxes	4,010	30,594	(26,584)	(86.9)%
Drilling and services	30,899	26,186	4,713	18.0%
Midstream and marketing	78,684	186,655	(107,971)	(57.8)%
Depreciation and depletion — natural gas and oil	176,027	290,917	(114,890)	(39.5)%
Depreciation, depletion and amortization — other	50,865	70,448	(19,583)	(27.8)%
Impairment	1,707,150	1,867,497	(160,347)	(8.6)%
General and administrative	100,256	109,372	(9,116)	(8.3)%
Gain on derivative contracts	(147,527)	(211,439)	63,912	(30.2)%
Loss (gain) on sale of assets	26,419	(9,273)	35,692	(384.9)%
Total operating costs and expenses	$2,196,068	$2,519,961	$(323,893)	(12.9)%

Production expense includes the costs associated with our exploration and production activities, including, but not limited to, lease operating expense and treating costs. Production expenses increased slightly to $169.3 million for the year ended December 31, 2009, compared to $159.0 million in 2008, primarily due to the slight increase in production from our 2009 drilling activity in the Permian Basin and West Texas. Production taxes decreased $26.6 million, or 86.9%, to $4.0 million for the year ended December 31, 2009, compared to $30.6 million in 2008, as a result of severance tax refunds totaling approximately $13.2 million in 2009 and the decreased prices received for production. As a result, production taxes on a unit-of-production basis decreased from $0.30 per Mcfe for 2008 to $0.04 per Mcfe for 2009.

Drilling and services expenses, which include operating expenses attributable to the drilling and oil field services segment and our CO_2 services companies, increased $4.7 million, or 18.0%, to $30.9 million in 2009 compared to $26.2 million in 2008. The increase is primarily due to less rig activity and lower profit margins in 2009, which resulted in a lower amount of costs associated with the drilling business being allocated to the full cost pool and an increased amount of such costs being expensed.

Midstream and marketing expenses decreased $108.0 million, or 57.8%, to $78.7 million in 2009 compared to $186.7 million in 2008, due primarily to lower prices paid for natural gas that we sold on behalf of third parties during 2009 than 2008.

Depreciation and depletion for our natural gas and oil properties decreased to $176.0 million during 2009 from $290.9 million in 2008. Our average depreciation and depletion per Mcfe decreased $1.19 to $1.68 from $2.87 in 2008 as a result of the cumulative full cost ceiling impairment, which reduced the carrying value of our natural gas and oil properties. The effect of the decrease in depreciation and depletion per Mcfe was slightly offset by the 3.4% increase in production for the year ended December 31, 2009 compared to 2008.

Depreciation, depletion and amortization ("DD&A") for our other assets consists primarily of depreciation of our drilling rigs, midstream gathering and compression facilities and other equipment. The $19.6 million decrease in DD&A for our other assets is attributable primarily to the change in asset lives of certain of our drilling, oil field service, midstream and other assets to align with industry average lives for similar assets. We calculate depreciation of property and equipment using the straight-line method over the estimated useful lives of the assets, which range from 3 to 39 years.

During 2009, we recorded a cumulative non-cash impairment charge of $1,693.3 million on our properties as total capitalized costs of our natural gas and oil properties exceeded our full cost ceiling limitation at both March 31, 2009 and December 31, 2009. Additional impairment expenses of $10.0 million and $3.9 million in 2009 are related to the decline in market value of our spare parts inventory and buildings that we determined will not have use or value in the future, respectively. At December 31, 2008, we recorded a non-cash full cost ceiling limitation impairment charge of $1,855.0 million on our properties. Additional impairment expenses in 2008 related to the impairment of our investment in and notes receivable due from Larclay.

General and administrative expenses decreased 8.3% to $100.3 million in 2009 from $109.4 million in 2008. The decrease is attributable, in part, to lower administrative costs due to the decrease in the number of people we employed for the year. As of December 31, 2009, we had 466 corporate employees compared to 528 at December 31, 2008. Also contributing to the decrease are lower professional services and office costs as a result of focused cost control efforts. General and administrative expenses included non-cash stock compensation expense, net of amounts capitalized, of $20.5 million for the year ended December 31, 2009 compared to $18.8 million in 2008. Corporate salaries and wages were partially offset by capitalized general and administrative expenses of $22.3 million, which included $4.3 million of capitalized stock compensation, for 2009 and $19.1 million for 2008. In accordance with the full cost method of accounting, we capitalize, into the full cost pool, internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. There was no stock compensation capitalized in 2008.

Due to the continued decline in average natural gas and oil prices during 2009, we recorded a net gain of $147.5 million ($348.0 million realized gain and $200.5 million unrealized loss) on our derivatives contracts for 2009 compared to a $211.4 million net gain ($13.0 million realized loss and $224.4 million unrealized gain) in 2008. The realized gain of $348.0 million for the year ended December 31, 2009 is primarily due to a decline in natural gas prices at the time of settlement compared to the contract price. The unrealized loss recorded in 2009 is attributable to an increase in average natural gas prices at December 31, 2009 compared to December 31, 2008 or the contract date for contracts entered into during 2009.

The loss on sale of assets for the year ended December 31, 2009 is primarily due to the $26.1 million loss on the sale of our gathering and compression assets located in the Piñon Field. For the year ended December 31, 2008, the gain on sale of assets was attributable to the approximately $7.2 million gain on the sale of our assets located in the Piceance Basin of Colorado.

Other Income (Expense). Total other expense increased to $177.0 million for the year ended December 31, 2009 from $140.6 million in 2008. The increase is reflected in the table below.

	Year Ended December 31, 2009	Year Ended December 31, 2008	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 375	$ 3,569	$ (3,194)	(89.5)%
Interest expense	(185,691)	(147,027)	(38,664)	26.3%
Income from equity investments	1,020	1,398	(378)	(27.0)%
Other income, net	7,272	1,454	5,818	400.1%
Total other (expense) income	(177,024)	(140,606)	(36,418)	25.9%
Loss before income taxes	(1,782,048)	(1,478,753)	(303,295)	20.5%
Income tax benefit	(8,716)	(38,328)	29,612	(77.3)%
Net loss	$(1,773,332)	$(1,440,425)	$(332,907)	23.1%

Interest income decreased to $0.4 million in 2009 from $3.6 million in 2008. This decrease is generally due to lower excess cash levels during 2009 compared to 2008.

Interest expense increased to $185.7 million in 2009, from $147.0 million, net of $0.4 million of capitalized interest, in 2008. The increase in interest expense for 2009 is the result of higher average debt balances outstanding during 2009 compared to 2008.

During the year ended December 31, 2009, we reported income from equity investments of $1.0 million compared to $1.4 million in 2008. The slight decline in income from equity investments is due to the consolidation of GRLP beginning October 1, 2009 and Lariat's assignment of its 50% equity interest in Larclay to CWEI on April 15, 2009.

Other income, net increased to $7.3 million in 2009 from $1.5 million in 2008. The increase is generally due to $4.5 million of the $7.0 million break-up fee provided for in the Crusader Purchase Agreement. Approximately $2.5 million of the break-up fee was recorded in general and administrative expenses to offset Crusader Acquisition related fees and expenses recorded therein.

We reported an income tax benefit of $8.7 million for the year ended December 31, 2009 compared to an income tax benefit of $38.3 million in 2008. The 2009 income tax benefit represented an effective income tax rate of 0.5% compared to an effective income tax rate of 2.6% in 2008. The lower effective income tax rate associated with the net loss attributable to us before income taxes of $1,784.3 million is predominantly due to a valuation allowance on the net deferred tax asset. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence. The tax benefit of $8.7 million, net of the valuation allowance, for the year ended December 31, 2009 is due to various federal and state return-to-accrual adjustments.

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

Revenues. Total revenues increased 74.4% to $1,181.8 million for the year ended December 31, 2008 from $677.5 million in 2007. This increase was due to a $431.1 million increase in natural gas and oil sales and a $99.8 million increase in midstream and marketing revenues, partially offset by lower revenues in our drilling and services operations.

	Year Ended December 31, 2008	Year Ended December 31, 2007	$ Change	% Change
	(In thousands)			
Revenues:				
Natural gas and oil	$ 908,689	$477,612	$431,077	90.3%
Drilling and services	47,199	73,197	(25,998)	(35.5)%
Midstream and marketing	207,602	107,765	99,837	92.6%
Other	18,324	18,878	(554)	(2.9)%
Total revenues	$1,181,814	$677,452	$504,362	74.4%

Total natural gas and oil revenues increased $431.1 million to $908.7 million for the year ended December 31, 2008, compared to $477.6 million in 2007, primarily as a result of the increase in natural gas and oil production volumes and prices received on our production. Total natural gas production increased 68.2% to 87.4 Bcf in 2008 compared to 52.0 Bcf in 2007, while oil production increased 14.3% to 2,334 MBbls in 2008 from 2,042 MBbls in 2007. The average price received, excluding the impact of derivative contracts, for our natural gas and oil production increased 20.3% in 2008 to a combined equivalent price of $8.96 per Mcfe compared to $7.45 per Mcfe in 2007. The average price we received for our natural gas and oil production was negatively impacted by the significant decline in natural gas and oil prices experienced by the oil and gas industry in the fourth quarter of 2008.

Drilling and services revenues decreased 35.5% to $47.2 million in 2008 compared to $73.2 million in 2007. The decline in revenues is primarily attributable to an increase in the average number of our rigs operating on our properties, the increase in our ownership interest in our natural gas and oil properties resulting in decreases in services performed for third parties, and the decline in revenue earned per day by rigs working for third parties. The average daily rate we received per rig working for third parties declined to an average of $14,217 per rig per working day during 2008 from an average of $21,468 per rig per working day during 2007.

Midstream and marketing revenues increased $99.8 million, or 92.6%, to $207.6 million for the year ended December 31, 2008, compared to $107.8 million in 2007. This increase was primarily due to larger production volumes transported and marketed for third parties with ownership in our wells or ownership in other wells connected to our gathering systems during 2008 compared to 2007. Higher natural gas prices prevalent during the first nine months of 2008 compared to 2007 also contributed to the increase.

Operating Costs and Expenses. Total operating costs and expenses increased to $2,520.0 million during 2008, compared to $490.6 million in 2007, primarily as a result of our full cost ceiling impairment along with increases in our production-related costs, midstream and marketing expenses, general and administrative expenses and depreciation, depletion and amortization. These increases were partially offset by decreases in costs attributable to our drilling and services operations as well as increased gains on commodity derivative contracts.

	Year Ended December 31,			
	2008	2007	$ Change	% Change
	(In thousands)			
Operating costs and expenses:				
Production	$ 159,004	$106,192	$ 52,812	49.7%
Production taxes	30,594	19,557	11,037	56.4%
Drilling and services	26,186	44,211	(18,025)	(40.8)%
Midstream and marketing	186,655	94,253	92,402	98.0%
Depreciation and depletion — natural gas and oil	290,917	173,568	117,349	67.6%
Depreciation, depletion and amortization — other	70,448	53,541	16,907	31.6%
Impairment	1,867,497	—	1,867,497	100.0%
General and administrative	109,372	61,780	47,592	77.0%
Gain on derivative instruments	(211,439)	(60,732)	(150,707)	248.2%
Gain on sale of assets	(9,273)	(1,777)	(7,496)	421.8%
Total operating costs and expenses	$2,519,961	$490,593	$2,029,368	413.7%

Production expenses increased $52.8 million to $159.0 million for the year ended December 31, 2008, compared to $106.2 million in 2007, primarily due to increased production from our 2008 drilling activity and the increase in the number of producing wells in which we have a working interest. Production taxes increased $11.0 million, or 56.4%, to $30.6 million for the year ended December 31, 2008, compared to $19.6 million in 2007, primarily as a result of the increase in production and the increased prices received for production during the year ended December 31, 2008.

Drilling and services expenses decreased $18.0 million, or 40.8%, to $26.2 million in 2008 compared to $44.2 million in 2007, primarily due to the increase in the number and working interest ownership of the wells we drilled for our own account and a decrease in services performed for third parties.

Midstream and marketing expenses increased $92.4 million, or 98.0%, to $186.7 million in 2008 compared to $94.3 million in 2007, due primarily to the larger production volumes transported and marketed during the year ended December 31, 2008 on behalf of third parties compared to 2007.

Depreciation and depletion for our natural gas and oil properties increased to $290.9 million during 2008 from $173.6 million in 2007. Our depreciation and depletion per Mcfe increased $0.17 to $2.87 from $2.70 in 2007. The increase was primarily attributable to the increase in our depreciable properties, higher future development costs and increased production.

The $16.9 million increase in DD&A for our other assets was attributable primarily to higher carrying costs of our rigs, due to upgrades and retrofitting during 2007, and our midstream gathering and treating assets, due to upgrades made throughout 2007 and 2008.

At December 31, 2008, we recorded a non-cash impairment charge of $1,855.0 million on our properties as total capitalized costs of our natural gas and oil properties exceeded our full cost ceiling limitation. There was no full cost ceiling impairment as of December 31, 2007. The additional impairment expenses in 2008 related to the impairment of our investment in and notes receivable due from Larclay.

General and administrative expenses increased 77.0% to $109.4 million in 2008 from $61.8 million in 2007. The increase was attributable to an increase in corporate salaries and wages, including non-cash stock compensation expense. The increase in corporate salaries was primarily due to the increase in corporate and support staff added to accommodate our growth. As of December 31, 2008, we had 528 corporate employees compared to 335 at December 31, 2007. Included in corporate salaries and wages was non-cash stock compensation expense of $18.8 million in 2008 and $7.2 million in 2007. Corporate salaries and wages were partially offset by capitalized general and administrative expenses of $19.1 million for 2008 and $4.6 million for 2007.

Due to the decline in average natural gas and oil prices during the second half of 2008, we recorded a net gain of $211.4 million ($13.0 million realized loss and $224.4 million unrealized gain) on our derivatives contracts for 2008 compared to a $60.7 million gain ($34.5 million realized gain and $26.2 million unrealized gain) in 2007. The unrealized gain recorded during 2008 was attributable to a decrease in average natural gas prices at December 31, 2008 compared to the average natural gas prices at December 31, 2007 or the various contract dates for contracts entered into during 2008.

Other Income (Expense). Total other expense increased to $140.6 million for the year ended December 31, 2008 from $107.4 million in 2007. The increase is reflected in the table below.

	Year Ended December 31, 2008	2007	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 3,569	$ 4,694	$ (1,125)	(24.0)%
Interest expense	(147,027)	(117,185)	(29,842)	25.5%
Income from equity investments	1,398	4,372	(2,974)	(68.0)%
Other income, net	1,454	729	725	99.5%
Total other (expense) income	(140,606)	(107,390)	(33,216)	30.9%
(Loss) income before income taxes	(1,478,753)	79,469	(1,558,222)	(1,960.8)%
Income tax (benefit) expense	(38,328)	29,524	(67,852)	(229.8)%
Net (loss) income	$(1,440,425)	$ 49,945	$(1,490,370)	(2,984.0)%

Interest income decreased to $3.6 million in 2008 from $4.7 million in 2007. This decrease was generally due to lower excess cash levels during 2008 compared to 2007.

Interest expense increased to $147.0 million, net of $0.4 million of capitalized interest, in 2008, from $117.2 million, net of $2.0 million of capitalized interest, in 2007. The increase in interest expense for 2008 was the result of higher average debt balances outstanding during 2008 compared to 2007. An $8.7 million unrealized loss related to our interest rate swap also contributed to the increase in interest expense for 2008. In March 2007, the unamortized debt issuance costs totaling $12.5 million related to our senior bridge facility were expensed resulting in higher interest expense.

During the year ended December 31, 2008, we reported income from equity investments of $1.4 million compared to $4.4 million in 2007 due to decreases in profitability experienced by our unconsolidated equity investees, Larclay and GRLP.

We reported an income tax benefit of $38.3 million for the year ended December 31, 2008 compared to income tax expense of $29.5 million in 2007. The 2008 income tax benefit represented an effective income tax rate of 2.6% compared to 37.0% in 2007. The low effective income tax rate associated with the loss before income taxes is predominantly due to a valuation allowance being established against our net deferred tax asset. Our deferred tax position changed from a net deferred tax liability as of December 31, 2007 to a net deferred tax asset as of December 31, 2008 due to the recording of a full cost ceiling impairment of $1,855.0 million. The valuation allowance served to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are cash flow generated from operations, borrowings under our senior credit facility, the issuance of equity and debt securities, and to a lesser extent, the sale of assets. Our primary uses of capital are expenditures related to our natural gas and oil properties and other fixed assets, the acquisition of natural gas and oil properties and the repayment of amounts outstanding on our senior credit facility and interest payments on our outstanding debt. We maintain access to funds that may be needed to meet capital funding requirements through our senior credit facility.

Working Capital

Our working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under our credit arrangements and changes in the fair value of our outstanding commodity derivative instruments. Absent any significant effects from our commodity derivative instruments, we typically have a working capital deficit or a relatively small amount of positive working capital because our capital spending generally has exceeded our cash flows from operations and we generally use excess cash to pay down borrowings outstanding under our credit arrangements.

At December 31, 2009, we had a working capital surplus of $30.4 million compared to a deficit of $46.7 million at December 31, 2008. Current assets decreased $99.9 million at December 31, 2009, compared to current assets at December 31, 2008, primarily due to a $95.1 million decrease in our current derivative contract assets resulting from the increase in natural gas and oil market prices compared to the contract prices. Current liabilities decreased $177.1 million primarily as a result of a decrease of $162.7 million in accounts payable.

Cash Flows

Our cash flows for the years ended December 31, 2009, 2008 and 2007 are presented in the following table and discussed below:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows:			
Cash flows provided by operating activities	$ 311,559	$ 579,189	$ 357,452
Cash flows used in investing activities	(1,247,059)	(1,909,443)	(1,385,581)
Cash flows provided by financing activities	942,725	1,267,755	1,052,316
Net increase (decrease) in cash and cash equivalents	$ 7,225	$ (62,499)	$ 24,187

Cash Flows from Operating Activities

Our operating cash flow is mainly influenced by the prices we receive for our natural gas and oil production; the quantity of natural gas we produce and, to a lesser extent, the quantity of oil we produce; the demand for our drilling rigs and oil field services and the rates we are able to charge for these services; and the margins we obtain from our natural gas and CO_2 gathering and treating contracts.

Net cash provided by operating activities for the years ended December 31, 2009 and 2008 was $311.6 million and $579.2 million, respectively. The decrease in cash provided by operating activities from 2008 to 2009 is primarily due to our $454.0 million decrease in revenues as a result of our 51.6% decrease in prices received on our production during 2009. These decreases were partially offset by increases in realized gains on our commodity derivative contracts settled during 2009.

Cash flows provided by operating activities increased $221.7 million to $579.2 million in 2008 from $357.5 million in 2007 primarily due to our $504.4 million increase in revenues as a result of our 57.9% increase in production volumes related to our drilling activities during 2008. These increases were partially offset by increases in midstream and marketing expenses and general and administrative costs such as salaries and wages.

Cash Flows from Investing Activities

We dedicate and expect to continue to dedicate a substantial portion of our capital expenditure program toward the exploration, development, production and acquisition of natural gas and oil reserves. These capital expenditures are necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive natural gas and oil industry.

Cash flows used in investing activities decreased to $1,247.1 million during 2009 from $1,909.4 million in 2008 due to the reduction in our capital expenditure program in 2009. Capital expenditures, excluding acquisitions, decreased $1,532.7 million to $645.1 million for the year ended December 31, 2009 compared to $2,177.8 million for the same period in 2008 primarily due to our decreased drilling activities. The decrease in cash outflows for capital expenditures was partially offset by the Forest Acquisition which resulted in $795.1 million of cash outflows in 2009. Cash outflows from capital expenditures in 2009 were partially offset by approximately $255.0 million in combined net proceeds from the sale of our gathering and compression assets located in the Piñon Field and our deep drilling rights in East Texas. Cash outflows from capital expenditures in 2008 were partially offset by approximately $147.2 million in proceeds from the sale of our assets located in the Piceance Basin of Colorado.

Cash flows used in investing activities increased to $1,909.4 million during 2008 from $1,385.6 million in 2007 due to the expansion of our capital expenditure program in 2008. During 2008, our capital expenditures, excluding capital expenditures accrued at December 31, 2008, were $1,818.7 million in our exploration and production segment, $52.9 million for drilling and oil field services, $131.4 million for midstream gas services and $55.4 million for other capital expenditures.

Capital Expenditures. Our capital expenditures, on an accrual basis, by segment for the past three years are summarized below:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Capital expenditures:			
Exploration and production	$ 555,809	$1,909,078	$1,046,552
Drilling and oil field services	4,090	52,869	123,232
Midstream gas services	52,425	160,460	63,828
Other	32,818	55,440	47,236
Capital expenditures, excluding acquisitions	645,142	2,177,847	1,280,848
Acquisitions	795,074	—	116,650
Total	$1,440,216	$2,177,847	$1,397,498

Cash Flows from Financing Activities

Our financing activities provided $942.7 million in cash for the year ended December 31, 2009 compared to $1,267.8 million for the year ended December 31, 2008. Proceeds from borrowings were $2,619.6 million for the year ended December 31, 2009 compared to $3,252.2 million for 2008, as a result of lower borrowings during 2009 under our senior credit facility. We repaid borrowings of approximately $2,417.0 million during 2009, leaving net borrowings of approximately $202.6 million for the year. During 2009, we completed registered underwritten offerings of an aggregate of 40,080,000 shares of our common stock. Net proceeds from these offerings were approximately $324.8 million. Also in 2009, we completed private placements of an aggregate of 4,650,000 shares of our convertible perpetual preferred stock. Net proceeds were approximately $443.2 million.

Proceeds from borrowings increased to $3,252.2 million for the year ended December 31, 2008 compared to $1,331.5 million for 2007, mainly as a result of our issuance of $750.0 million in 8.0% Senior Notes due 2018 in May 2008 and draw downs on our senior credit facility. We repaid borrowings of approximately $1,944.5 million during 2008, leaving net borrowings of approximately $1,307.7 million for the year. Our financing activities provided $1,267.8 million in cash for the year ended December 31, 2008 compared to $1,052.3 million for the year ended December 31, 2007.

Indebtedness

Senior Credit Facility. Our senior credit facility limits the amounts we can borrow to a borrowing base amount, currently $850.4 million. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional re-determination of the borrowing base per calendar year. We may request up to two unscheduled re-determinations per year. The borrowing base is determined based upon proved developed producing reserves, proved developed non-producing reserves, and proved undeveloped reserves. Our borrowing base is redetermined in April and October of each year based on proved reserves. Because the value of our proved reserves is a key factor in determining the amount of the borrowing base, our success in developing reserves, as well as changing commodity prices, may affect the borrowing base of our senior credit facility.

The senior credit facility contains various covenants that limit the ability of us and certain of our subsidiaries to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of our assets. Additionally, the senior credit facility limits the ability of us and certain of our subsidiaries to incur additional indebtedness with certain exceptions. The senior credit facility also contains financial covenants, including maintaining agreed levels for the (i) ratio of total funded debt to EBITDAX (as defined in the senior credit facility), which may not exceed 4.5:1.0 at each quarter end calculated using the last four completed fiscal quarters, (ii) ratio of EBITDAX to interest expense plus current maturities of long-term debt, which must be at least 2.5:1.0 at each quarter end calculated using the last four completed fiscal quarters, and (iii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. In the current ratio calculation (as defined in the senior credit facility) any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company's derivative contracts are disregarded. As of December 31, 2009, we were in compliance with all of the financial covenants under the senior credit facility.

Notes Payable. Long-term obligations under outstanding notes payable consist of the following at December 31, 2009 (in thousands):

Other notes payable	$ 35,327
Senior Floating Rate Notes due 2014	350,000
8.625% Senior Notes due 2015	650,000
9.875% Senior Notes due 2016, net of $14,479 discount	351,021
8.0% Senior Notes due 2018	750,000
8.75% Senior Notes due 2020, net of $7,410 discount	442,590
Total debt	$2,578,938

The indentures governing the senior notes referred to above contain financial covenants similar to those of the senior credit facility and include limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers.

For more information about the senior credit facility, the senior notes and our other long-term debt obligations, see Note 12 to the consolidated financial statements included in Item 8 of this report.

Outlook

For 2010, we have budgeted $860.0 million for capital expenditures, excluding acquisitions. The majority of our capital expenditures will be discretionary and could be curtailed if our cash flows decline from expected levels or we are unable to obtain capital on attractive terms. We may increase or decrease planned capital expenditures depending on natural gas prices, asset sales and the availability of capital through the issuance of additional long-term debt or equity.

Our revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for natural gas and oil, each of which depend on numerous factors beyond our control such as economic conditions, regulatory developments and competition from other energy sources. The energy markets historically have been volatile and natural gas and oil prices in 2009 were substantially lower than in 2008 and 2007 and may be subject to significant fluctuations in the future. Our derivative arrangements serve to mitigate a portion of the effect of this price volatility on our cash flows, and while derivative contracts for the majority of expected 2010, 2011 and 2012 oil production are in place, there are no fixed price swap derivative contracts in place for our natural gas production beyond 2010. In addition, we will need to incur capital expenditures in 2010 to achieve production targets required to meet our commitments to deliver gas under certain gathering and treating arrangements. We are dependent on availability under the senior credit facility, along with cash flows from operating activities, to fund those capital expenditures. Based on anticipated natural gas and oil prices and availability under the senior credit facility, we expect to be able to fund our planned capital expenditures for 2010. However, a substantial or extended decline in natural gas and oil prices and/or less than anticipated new production could have a material adverse effect on our financial position, results of operations, cash flows and quantities of natural gas and oil reserves that may be economically produced and could impact our ability to comply with the financial covenants under the senior credit facility, which in turn would limit further borrowings to fund capital expenditures. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information regarding our derivative contracts.

As of December 31, 2009, our cash and cash equivalents were $7.9 million and we had approximately $2.6 billion in total debt outstanding with no amounts outstanding under our senior credit facility. As of December 31, 2009, we were in compliance with all of the covenants under all of our senior notes and our senior credit facility. As of February 25, 2010, our cash and cash equivalents were approximately $8.7 million, the balance outstanding under our senior credit facility was $59.6 million and we had $25.4 million outstanding in letters of credit.

If future capital expenditures exceed operating cash flow and cash on hand, funds would likely be supplemented as needed by borrowings under our senior credit facility. We may choose to refinance borrowings outstanding under the facility by issuing long-term debt or equity in the public or private markets, or both.

Debt and equity capital markets experienced adverse conditions during the latter part of 2008 and into 2009. Continued volatility in the capital markets may increase costs associated with issuing debt due to increased interest rates, and may affect our ability to access these markets. Currently, we do not believe our liquidity has been, or in the near future will be, materially affected by recent events in the global financial markets. Nevertheless, we continue to monitor events and circumstances surrounding each of the 27 lenders under our senior credit facility. To date, the only disruption in our ability to access the full amounts available under our senior credit facility was the bankruptcy of Lehman Brothers, a lender responsible for 0.29% of the obligations under our senior credit facility. We cannot predict with any certainty the impact to us of any further disruptions in the credit markets.

Based upon the current level of operations and anticipated growth, we believe our cash flow from operations, current cash on hand and availability under our senior credit facility, together with potential access to the credit markets, will be sufficient to meet our capital expenditures budget, debt service requirements and working capital needs for the next 12 months. We have the ability to reduce our capital expenditures budget if cash flows are not available.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2009 is provided in the following table:

	Payments Due by Year						
	2010	2011	2012	2013	2014	After 2014	Total
	(In thousands)						
Long-term debt	$ 12,003	$ 7,295	$ 1,051	$ 1,121	$ 1,191	$2,578,166	$2,600,827
Interest on senior notes(1)	205,232	205,232	205,232	205,232	205,232	526,233	1,552,393
Firm transportation	35,307	30,391	30,612	24,725	16,483	65,979	203,497
Gas gathering agreement	22,226	33,780	42,814	42,634	42,360	305,390	489,204
Asset retirement obligations	2,553	5,801	4,344	90	690	97,659	111,137
Other	33,695	10,300	5,117	4,249	1,998	12,499	67,858
Total	$311,016	$292,799	$289,170	$278,051	$267,954	$3,585,926	$5,024,916

(1) Based on interest rates as of December 31, 2009.

We maintain deposits in bank trust and escrow accounts as required by MMS, surety bond underwriters, purchase agreements or other settlement agreements to satisfy our eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of 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 our financial statements requires us to make assumptions and prepare estimates that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and revenues and expenses. We base our estimates on historical experience and various other assumptions that we believe are reasonable; however, actual results may differ. See "Note 1 — Summary of Organization and Significant Accounting Policies" to the consolidated financial statements included in Item 8 of this report for a discussion of our significant accounting policies.

In January 2010, the Financial Accounting Standards Board issued ASU 2010-03 to align the oil and gas reserve estimation and disclosure requirements of Extractive Industries — Oil and Gas Topic of the Accounting Standards Codification with the requirements in the SEC's final rule, *Modernization of the Oil and Gas Reporting Requirements*. We implemented ASU 2010-03 as of December 31, 2009. Key items in the new rules include changes to the pricing used to estimate reserves and calculate the full cost ceiling limitation whereby a 12-month average price is used rather than a single day spot price, the use of new technology for determining reserves, the ability to include nontraditional resources in reserves and permitting disclosure of probable and possible reserves.

Proved Reserves. Approximately 95% of our reserves are estimated on an annual basis by independent petroleum engineers. Estimates of proved reserves are based on the quantities of natural gas and oil that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond our control. The estimation process is very complex and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2009, 2008 and 2007, we revised our proved reserves from prior years' reports by approximately (1,191.9) Bcfe, 452.6 Bcfe and 351.6 Bcfe, respectively, due to market prices during or at the end of the applicable period or production performance indicating more (or less) reserves in place or larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries. Estimates of proved reserves are key components of our most significant financial estimates involving our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. These revisions may be material and could materially affect our future depreciation and depletion expenses.

Method of accounting for natural gas and oil properties. The accounting for our business is subject to special accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. We follow the full cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of natural gas and oil properties are capitalized. Exploration and development costs include dry well costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding natural gas and oil reserves. Amortization of natural gas and oil properties is provided using the unit-of-production method based on estimated proved natural gas and oil reserves. Sales and abandonments of natural gas and oil properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved natural gas and oil reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion and impairment of oil and natural gas properties are generally calculated on a well by well, lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation, depletion and amortization rate, and we will not have exploration expenses that successful efforts companies frequently have.

In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of natural gas and oil properties, net of accumulated depreciation, depletion, and amortization, less related deferred income taxes, may not exceed an amount equal to the present value of future net revenues from proved natural gas and oil reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects (the "ceiling limitation"). Beginning with the December 31, 2009 calculation, our full cost ceiling limitation is calculated using the 12-month average natural gas and oil prices for the most recent 12 months as of the balance sheet date and adjusted for "basis" or location differential, held constant over the life of the reserves. Prior to December 31, 2009, the full cost ceiling limitation calculation required companies to use natural gas and oil prices on the last day of the period. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down is not reversible at a later date. During the year ended December 31, 2009, total capitalized costs of our natural gas and oil properties exceeded our ceiling limitation resulting in a non-cash ceiling impairment of $1,693.3 million, $388.9 million of which was incurred in the fourth quarter under the current SEC rule and $1,304.4 million of which was incurred in the first quarter under the rules in effect at the time. For the year ended December 31, 2008, total capitalized costs of our natural gas and oil properties exceeded our ceiling limitation resulting in a non-cash ceiling impairment of $1,855.0 million calculated under the previous rules.

Unevaluated Properties. The balance of unevaluated properties consists of capital costs incurred for undeveloped acreage, wells and production facilities in progress and wells pending determination, together with capitalized interest costs for these projects. These costs are initially excluded from our amortization base until the outcome of the project has been determined or, generally, until it is known whether proved reserves will or will not be assigned to the property. We assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. We assess our properties on an individual basis or as a group if properties are individually insignificant. Our assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization. We estimate that substantially all of our costs classified as unproved as of the balance sheet date will be evaluated and transferred within a six-year period from the date of acquisition, contingent on our capital expenditures and drilling program.

Asset Retirement Obligations. Asset retirement obligations represent the estimated future abandonment costs of tangible long-lived assets such as platforms, wells, service assets, pipelines and other facilities. We estimate the fair value of an asset's retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. We employ a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions, including an inflation rate, our credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third-party quotes and current actual costs. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Revenue Recognition and Gas Balancing. Natural gas and oil revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. We account for natural gas and oil production imbalances using the sales method, whereby we recognize revenue on all natural gas and oil sold to our customers notwithstanding the fact that its ownership may be less than 100% of the natural gas and oil sold. Liabilities are recorded for imbalances greater than our proportionate share of remaining estimated natural gas and oil reserves.

We recognize revenues and expenses generated from day work drilling contracts as the services are performed, since we do not bear the risk of completion of the well.

We may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another are recognized over the term of the related drilling contract. The contract terms typically range from 20 to 90 days.

Midstream gas services segment revenues consist mostly of gas marketing revenue; however, gas marketing is a very low-margin business. Midstream gas services are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. On a consolidated basis, midstream and marketing revenues represent natural gas sold on behalf of third parties and the fees we charge related to gathering, compressing and treating this gas. Gas marketing operating costs represent payments made to third parties for the proceeds from the sale of gas owned by such parties, net of any applicable margin and actual costs to gather, compress and treat the gas that we charge. In general, natural gas purchased and sold by our midstream gas business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. The primary factors affecting midstream gas services are the quantity of natural gas we gather, treat and market and the prices we pay and receive for natural gas.

Revenue from sales of CO_2 is recognized when the product is delivered to the customer. We recognize service fees related to the transportation of CO_2 as revenue when the related service is provided.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of drilling equipment is recorded using the straight-line method based on estimated useful lives. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 39 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause us to reduce the carrying value of property and equipment.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed from the accounts and any resulting gain or loss is reflected in operations.

Income Taxes. Deferred income taxes are recorded for temporary differences between financial statement and income tax basis. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. Deferred tax assets are recognized for temporary differences that will be deductible in future years' tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years' tax returns.

As of December 31, 2009, we have a full valuation allowance against our net deferred tax asset. Our deferred tax position changed from a net deferred tax liability as of December 31, 2007 to a net deferred tax asset as of December 31, 2008 due to the recording of a full cost ceiling impairment of $1,855.0 million. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence. We increased the valuation allowance for the period ended December 31, 2009 by $641.3 million as a result of not recording a benefit for the current period net loss attributable to us before income taxes of $1,784.3 million.

Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in natural gas and oil prices, we enter into interest rate swaps and natural gas and oil futures contracts.

We recognize all of our derivative contracts as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative contract depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative contracts that are designated and qualify as hedging instruments, we designate the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge. For derivative contracts not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of our derivatives was designated as hedging instruments during 2009, 2008 and 2007.

New Accounting Pronouncements

For a discussion of recently adopted accounting standards, see Note 1 to our consolidated financial statements included in Item 8 of this report.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Various statements contained in this report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements may include projections and estimates concerning 2010 capital expenditures, our liquidity and capital resources, effects of acquisitions, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of our business strategy and other statements concerning our operations, economic performance and financial condition. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. We have based these forward-looking statements on our current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. The forward-looking statements in this report speak only as of the date of this report; we disclaim any obligation to update or revise these statements unless required by securities law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in "Risk Factors" in Item 1A of this report including the following:

- the volatility of natural gas and oil prices;
- uncertainties in estimating natural gas and oil reserves;
- the need to replace the natural gas and oil reserves we produce;
- our ability to execute our growth strategy by drilling wells as planned;
- the need to drill productive, economically viable natural gas and oil wells;
- risks and liabilities associated with acquired properties;
- amount, nature and timing of capital expenditures, including future development costs, required to develop the WTO and other undeveloped areas;
- concentration of operations in the WTO;

- economic viability of WTO production with high CO_2 content;
- availability of natural gas production for our midstream services operations;
- limitations of seismic data;
- risks associated with drilling natural gas and oil wells;
- availability of satisfactory natural gas and oil marketing and transportation;
- availability and terms of capital;
- substantial existing indebtedness;
- limitations on operations resulting from debt restrictions and financial covenants;
- potential financial losses or earnings reductions from commodity derivatives;
- competition in the oil and gas industry;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we operate;
- costs to comply with current and future governmental regulation of the oil and gas industry, including environmental, health and safety laws and regulations; and
- the need to maintain adequate internal control over financial reporting.

Item 7A. *Quantitative and Qualitative Disclosures about Market Risk*

General

The discussion in this section provides information about the financial instruments we use to manage commodity prices and interest rate volatility. All contracts are settled in cash and do not require the actual delivery of a commodity at settlement.

Commodity Price Risk. Our most significant market risk relates to the prices we receive for our natural gas and oil production. Due to the historical volatility of these commodities, we periodically have entered into, and expect in the future to enter into, derivative arrangements for the purpose of reducing the variability of natural gas and oil prices we receive for our production. From time to time, we enter into commodity pricing derivative contracts for a portion of our anticipated production volumes depending upon management's view of opportunities under the then current market conditions. We do not intend to enter into derivative contracts that would exceed our expected production volumes for the period covered by the derivative arrangement. Our current credit agreement limits our ability to enter into derivative transactions to 85% of expected production volumes from estimated proved reserves. Future credit agreements could require a minimum level of commodity price hedging.

The use of derivative contracts also involves the risk that the counterparties will be unable to meet their obligations under the contracts. Our derivative contracts are with multiple counterparties to minimize our exposure to any individual counterparty. As of December 31, 2009, we had 18 approved derivative counterparties, 17 of which are lenders under our senior credit facility. We currently have derivative contracts outstanding with 11 of these counterparties. We have no derivative contracts in 2010 and beyond with counterparties other than those that are lenders under our senior credit facility.

We use, and may continue to use, a variety of commodity-based derivative contracts, including collars, fixed-price swaps and basis protection swaps. Our fixed price swap transactions are settled based upon New York Mercantile Exchange prices, and our basis protection swap transactions are settled based upon the index price of natural gas at the Waha hub, a West Texas gas marketing and delivery center and the Houston Ship Channel. Settlement for natural gas derivative contracts occurs in the production month.

We have not designated any of our derivative contracts as hedges for accounting purposes. We record all derivative contracts on the balance sheet at fair value, which reflects changes in natural gas and oil prices. We establish fair value of our derivative contracts by price quotations obtained from counterparties to the derivative contracts. Changes in fair values of our derivative contracts are recognized as unrealized gains and losses in current period earnings. As a result, our current period earnings may be significantly affected by changes in fair value of our commodity derivative contracts. Changes in fair value are principally measured based on period-end prices compared to the contract price.

At December 31, 2009, our open natural gas and oil commodity derivative contracts consisted of the following:

Natural Gas

Period and Type of Contract	Notional (MMcf)(1)	Weighted Avg. Fixed Price
January 2010 — March 2010		
Price swap contracts	20,475	$ 7.95
Basis swap contracts	20,250	$(0.74)
April 2010 — June 2010		
Price swap contracts	19,793	$ 7.32
Basis swap contracts	20,475	$(0.74)
July 2010 — September 2010		
Price swap contracts	20,010	$ 7.55
Basis swap contracts	20,700	$(0.74)
October 2010 — December 2010		
Price swap contracts	20,010	$ 7.97
Basis swap contracts	20,700	$(0.74)
January 2011 — March 2011		
Basis swap contracts	25,650	$(0.47)
April 2011 — June 2011		
Basis swap contracts	25,935	$(0.47)
July 2011 — September 2011		
Basis swap contracts	26,220	$(0.47)
October 2011 — December 2011		
Basis swap contracts	26,220	$(0.47)
January 2012 — March 2012		
Basis swap contracts	28,210	$(0.55)
April 2012 — June 2012		
Basis swap contracts	28,210	$(0.55)
July 2012 — September 2012		
Basis swap contracts	28,520	$(0.55)
October 2012 — December 2012		
Basis swap contracts	28,520	$(0.55)
January 2013 — March 2013		
Basis swap contracts	3,600	$(0.46)
April 2013 — June 2013		
Basis swap contracts	3,640	$(0.46)
July 2013 — September 2013		
Basis swap contracts	3,680	$(0.46)
October 2013 — December 2013		
Basis swap contracts	3,680	$(0.46)

(1) Assumes ratio of 1:1 for Mcf to MMBtu.

Oil

Period and Type of Contract	Notional (in MBbls)	Weighted Avg. Fixed Price
January 2010 — March 2010		
Price swap contracts	990	$81.95
April 2010 — June 2010		
Price swap contracts	1,092	$82.05
July 2010 — September 2010		
Price swap contracts	1,104	$82.05
October 2010 — December 2010		
Price swap contracts	1,104	$82.05
January 2011 — March 2011		
Price swap contracts	1,170	$86.52
April 2011 — June 2011		
Price swap contracts	1,183	$86.52
July 2011 — September 2011		
Price swap contracts	1,196	$86.52
October 2011 — December 2011		
Price swap contracts	1,196	$86.52
January 2012 — March 2012		
Price swap contracts	1,092	$88.26
April 2012 — June 2012		
Price swap contracts	1,092	$88.26
July 2012 — September 2012		
Price swap contracts	1,104	$88.26
October 2012 — December 2012		
Price swap contracts	1,104	$88.26

The following table summarizes the cash settlements and valuation gains and losses on our commodity derivative contracts for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	2009	2008	2007
Realized (gain) loss	$(348,022)	$ 12,981	$(34,494)
Unrealized loss (gain)	200,495	(224,420)	(26,238)
Gain on commodity derivative contracts	$(147,527)	$(211,439)	$(60,732)

Credit Risk. A portion of our liquidity is concentrated in derivative contracts that enable us to mitigate a portion of our exposure to natural gas and oil prices and interest rate volatility. We periodically review the credit quality of each counterparty to our derivative contracts and the level of financial exposure we have to each counterparty to limit our credit risk exposure with respect to these contracts. Additionally, we apply a credit default risk rating factor for our counterparties in determining the fair value of our derivative contracts. The counterparties for all of our hedging transactions have an "investment grade" credit rating. The weighted average credit default swap rate for our counterparties was 0.3% and 2.3% at December 31, 2009 and 2008, respectively.

Our ability to fund our capital expenditure budget is partially dependent upon the availability of funds under our senior credit facility. In order to mitigate the credit risk associated with individual financial institutions committed to participate in our senior credit facility, our bank group consists of 27 financial institutions with commitments ranging from 0.25% to 6.3%. Lehman Brothers, a lender under our senior credit facility, declared bankruptcy on October 3, 2008. As a result of the bankruptcy of Lehman Brothers and its parent company, Lehman Brothers Holdings Inc., on September 15, 2008, Lehman Brothers elected not to fund its pro rata share, or 0.29%, of borrowings requested by us under the facility. Although we do not currently expect this reduced amount available under the senior credit facility to impact our liquidity or business operations, the inability of one or more of our other lenders to fund their obligations under the facility could have a material adverse effect on our financial condition.

Interest Rate Risk. We are subject to interest rate risk on our long-term fixed and variable interest rate borrowings. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes us to (i) changes in market interest rates reflected in the fair value of the debt and (ii) the risk that we may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes us to short-term changes in market interest rates as our interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily LIBOR and the federal funds rate.

In addition to commodity price derivative arrangements, we may enter into derivative transactions to fix the interest we pay on a portion of the money we borrow under our credit agreement. In January 2008, we entered into a $350.0 million notional amount interest rate swap agreement with a financial institution that effectively fixed the interest rate on our variable rate term loan for the period from April 1, 2008 through April 1, 2011. As a result of the exchange of our variable rate term loan to Senior Floating Rate Notes, the interest rate swap is now used to fix the variable LIBOR interest rate on the Senior Floating Rate Notes at 6.26% through April 2011. In May 2009, we entered into a $350.0 million notional amount interest rate swap agreement with a financial institution that effectively fixed the interest rate on our Senior Floating Rate Notes at 6.69% for the period from April 1, 2011 through April 1, 2013. These swaps have not been designated as hedges.

Our interest rate swaps reduce our market risk on our Senior Floating Rate Notes. We use sensitivity analyses to determine the impact that market risk exposures could have on our variable interest rate borrowings if not for our interest rate swaps. Based on the $350.0 million outstanding balance of our Senior Floating Rate Notes at December 31, 2009, a one percent change in the applicable rates, with all other variables held constant, would have resulted in a change in our interest expense of approximately $3.5 million for the year ended December 31, 2009.

Unrealized gain of $0.4 million and unrealized loss of $8.7 million were recorded in interest expense in the consolidated statements of operations for the change in fair value of the interest rate swaps for the years ended December 31, 2009 and 2008, respectively. Realized loss of $6.2 million and realized gain of $1.3 million were included in interest expense in the consolidated statements of operations for years ended December 31, 2009 and 2008, respectively.

Item 8. *Financial Statements and Supplementary Data*

Our consolidated financial statements required by this item are included in this report beginning on page F-1.

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

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this annual report. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2009 to provide reasonable assurance that the information required to be disclosed by us in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to management, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm. The information required to be furnished pursuant to this item is set forth under the captions "Management's Report on Internal Control over Financial Reporting" and "Report of Independent Registered Public Accounting Firm" in Item 8 of this report.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

Not applicable.

PART III

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

The information required by this item is incorporated herein by reference to the following sections of our definitive proxy statement, which will be filed no later than April 30, 2010: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

Item 11. *Executive Compensation*

The information required by this item is incorporated herein by reference to the following sections of our definitive proxy statement, which will be filed no later than April 30, 2010: "Director Compensation," "Outstanding Equity Awards" and "Executive Officers and Compensation."

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

The information required by this item is incorporated herein by reference to the following sections of our definitive proxy statement, which will be filed no later than April 30, 2010: "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management."

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

The information required by this item is incorporated herein by reference to the following sections of our definitive proxy statement, which will be filed no later than April 30, 2010: "Related Party Transactions" and "Corporate Governance Matters."

Item 14. *Principal Accountant Fees and Services*

The information required by this item is incorporated herein by reference to the section captioned "Ratification of Selection of Independent Registered Public Accounting Firm" in our definitive proxy statement, which will be filed no later than April 30, 2010.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

The following documents are filed as a part of this report:

(1) *Consolidated Financial Statements*

Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.

(2) *Financial Statement Schedules*

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

(3) *Exhibits*

See Exhibit Index for a description of the exhibits filed as a part of this report.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Based on our evaluation on criteria for effective internal control over financial reporting described in *Internal Control — Integrated Framework*, our management concluded, that as of December 31, 2009, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ TOM L. WARD	/s/ DIRK M. VAN DOREN
Tom L. Ward President and Chief Executive Officer	Dirk M. Van Doren Executive Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of SandRidge Energy, Inc:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders' equity and of cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Report on Internal Control Over Financial Reporting." Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our audits (which were integrated audits in 2009 and 2008). 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, effective December 31, 2009, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Houston, Texas
March 1, 2010

SandRidge Energy, Inc., and Subsidiaries
Consolidated Balance Sheets

	December 31, 2009	December 31, 2008
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,861	$ 636
Accounts receivable, net:		
Trade	105,412	102,746
Related parties	64	6,327
Derivative contracts	105,994	201,111
Inventories	3,707	3,686
Costs in excess of billings	12,346	—
Other current assets	20,580	41,407
Total current assets	255,964	355,913
Natural gas and oil properties, using full cost method of accounting		
Proved	5,913,408	4,676,072
Unproved	281,811	215,698
Less: accumulated depreciation, depletion and impairment	(4,223,437)	(2,369,840)
	1,971,782	2,521,930
Other property, plant and equipment, net	461,861	653,629
Derivative contracts	—	45,537
Investments	—	6,088
Restricted deposits	32,894	32,843
Other assets	57,816	39,118
Total assets	$ 2,780,317	$ 3,655,058
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 12,003	$ 16,532
Accounts payable and accrued expenses:		
Trade	203,048	366,337
Related parties	860	230
Derivative contracts	7,080	5,106
Asset retirement obligation	2,553	275
Billings in excess of costs incurred	—	14,144
Total current liabilities	225,544	402,624
Long-term debt	2,566,935	2,358,784
Other long-term obligations	14,099	11,963
Derivative contracts	61,060	3,639
Asset retirement obligation	108,584	84,497
Total liabilities	2,976,222	2,861,507
Commitments and contingencies (Note 18)		
Equity:		
SandRidge Energy, Inc., stockholders' equity:		
Preferred stock, $0.001 par value, 50,000 shares authorized:		
8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at December 31, 2009 and no shares issued and outstanding at December 31, 2008; aggregate liquidation preference of $265,000 at December 31, 2009	3	—
6.0% Convertible perpetual preferred stock; 2,000 shares issued and outstanding at December 31, 2009 and no shares issued and outstanding at December 31, 2008; aggregate liquidation preference of $200,000 at December 31, 2009	2	—
Common stock, $0.001 par value, 400,000 shares authorized; 210,581 issued and 208,715 outstanding at December 31, 2009 and 167,372 issued and 166,046 outstanding at December 31, 2008	203	163
Additional paid-in capital	2,961,613	2,170,986
Treasury stock, at cost	(25,079)	(19,332)
Accumulated deficit	(3,142,699)	(1,358,296)
Total SandRidge Energy, Inc., stockholders' (deficit) equity	(205,957)	793,521
Noncontrolling interest	10,052	30
Total (deficit) equity	(195,905)	793,551
Total liabilities and equity	$ 2,780,317	$ 3,655,058

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Statements of Operations

	Years Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Revenues:			
Natural gas and oil	$ 454,705	$ 908,689	$ 477,612
Drilling and services	23,902	47,199	73,197
Midstream and marketing	86,028	207,602	107,765
Other	26,409	18,324	18,878
Total revenues	591,044	1,181,814	677,452
Expenses:			
Production	169,285	159,004	106,192
Production taxes	4,010	30,594	19,557
Drilling and services	30,899	26,186	44,211
Midstream and marketing	78,684	186,655	94,253
Depreciation and depletion — natural gas and oil	176,027	290,917	173,568
Depreciation, depletion and amortization — other	50,865	70,448	53,541
Impairment	1,707,150	1,867,497	—
General and administrative	100,256	109,372	61,780
Gain on derivative contracts	(147,527)	(211,439)	(60,732)
Loss (gain) on sale of assets	26,419	(9,273)	(1,777)
Total expenses	2,196,068	2,519,961	490,593
(Loss) income from operations	(1,605,024)	(1,338,147)	186,859
Other income (expense):			
Interest income	375	3,569	4,694
Interest expense	(185,691)	(147,027)	(117,185)
Income from equity investments	1,020	1,398	4,372
Other income, net	7,272	1,454	729
Total other (expense) income	(177,024)	(140,606)	(107,390)
(Loss) income before income tax (benefit) expense	(1,782,048)	(1,478,753)	79,469
Income tax (benefit) expense	(8,716)	(38,328)	29,524
Net (loss) income	(1,773,332)	(1,440,425)	49,945
Less: net income (loss) attributable to noncontrolling interest	2,258	855	(276)
Net (loss) income attributable to SandRidge Energy, Inc.	(1,775,590)	(1,441,280)	50,221
Preferred stock dividends and accretion	8,813	16,232	39,888
(Loss applicable) income available to SandRidge Energy, Inc., common stockholders	$(1,784,403)	$(1,457,512)	$ 10,333
Basic and Diluted Earnings Per Share:			
Net (loss) income attributable to SandRidge Energy, Inc.	$ (10.15)	$ (9.26)	$ 0.46
Preferred stock dividends	(0.05)	(0.10)	(0.37)
Basic and diluted (loss) income per share (applicable) available to SandRidge Energy, Inc., common stockholders	$ (10.20)	$ (9.36)	$ 0.09
Weighted average number of common shares outstanding:			
Basic	175,005	155,619	108,828
Diluted	175,005	155,619	110,041

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity

	SandRidge Energy, Inc., Stockholders								
	Convertible Perpetual Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Noncontrolling Interest	Total
	Shares	Amount	Shares	Amount					
	(In thousands)								
Balance, December 31, 2006	—	$—	91,604	$ 92	$ 574,868	$(17,835)	$ 92,693	$ 5,092	$ 654,910
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(144)	(144)
Stock offerings, net of $4.5 million in offering costs	—	—	50,160	50	1,113,314	—	—	—	1,113,364
Conversion of common stock to redeemable convertible preferred stock	—	—	(526)	(1)	(9,650)	—	—	—	(9,651)
Accretion on redeemable convertible preferred stock	—	—	—	—	—	—	(1,421)	—	(1,421)
Purchase of treasury stock	—	—	—	(1)	—	(1,660)	—	—	(1,661)
Common stock issued under retirement plans	—	—	32	—	379	917	—	—	1,296
Stock-based compensation	—	—	—	—	7,202	—	—	—	7,202
Issuance of restricted stock awards, net of cancellations	—	—	573	—	—	—	—	—	—
Net income (loss)	—	—	—	—	—	—	50,221	(276)	49,945
Redeemable convertible preferred stock dividends	—	—	—	—	—	—	(42,277)	—	(42,277)
Balance, December 31, 2007	—	—	141,843	140	1,686,113	(18,578)	99,216	4,672	1,771,563
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(5,497)	(5,497)
Accretion on redeemable convertible preferred stock	—	—	—	—	—	—	(7,636)	—	(7,636)
Conversion of redeemable convertible preferred stock	—	—	22,276	23	458,328	—	—	—	458,351
Purchase of treasury stock	—	—	—	—	—	(3,553)	—	—	(3,553)
Common stock issued under retirement plans	—	—	211	—	3,167	2,799	—	—	5,966
Stock-based compensation	—	—	—	—	18,784	—	—	—	18,784
Stock-based compensation excess tax benefit	—	—	—	—	4,594	—	—	—	4,594
Issuance of restricted stock awards, net of cancellations	—	—	1,716	—	—	—	—	—	—
Net (loss) income	—	—	—	—	—	—	(1,441,280)	855	(1,440,425)
Redeemable convertible preferred stock dividends	—	—	—	—	—	—	(8,596)	—	(8,596)
Balance, December 31, 2008	—	—	166,046	163	2,170,986	(19,332)	(1,358,296)	30	793,551
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(26)	(26)
Consolidation of Grey Ranch L.P.	—	—	—	—	—	—	—	7,790	7,790
Issuance of convertible perpetual preferred stock	4,650	5	—	—	443,205	—	—	—	443,210
Issuance of common stock	—	—	40,080	40	324,790	—	—	—	324,830
Purchase of treasury stock	—	—	—	—	—	(1,494)	—	—	(1,494)
Stock purchase — retirement plans	—	—	(373)	—	(602)	(4,253)	—	—	(4,855)
Stock-based compensation	—	—	—	—	27,098	—	—	—	27,098
Stock-based compensation excess tax benefit	—	—	—	—	(3,864)	—	—	—	(3,864)
Issuance of restricted stock awards, net of cancellations	—	—	2,962	—	—	—	—	—	—
Net (loss) income	—	—	—	—	—	—	(1,775,590)	2,258	(1,773,332)
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(8,813)	—	(8,813)
Balance, December 31, 2009	4,650	$ 5	208,715	$203	$2,961,613	$(25,079)	$(3,142,699)	$10,052	$ (195,905)

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$(1,773,332)	$(1,440,425)	$ 49,945
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Provision for doubtful accounts	214	1,748	—
Depreciation, depletion and amortization	226,892	361,365	227,109
Impairment	1,707,150	1,867,497	—
Debt issuance costs amortization	7,477	5,623	15,998
Discount amortization on long-term debt	990	—	—
Deferred income taxes	—	(47,530)	28,923
Provision for inventory obsolescence	—	—	203
Unrealized loss (gain) on derivative contracts	200,049	(215,675)	(26,238)
Loss (gain) on sale of assets	26,419	(9,273)	(1,777)
Interest income — restricted deposits	(51)	(402)	(1,354)
Income from equity investments	(1,020)	(1,398)	(4,372)
Stock-based compensation	22,793	18,784	7,202
Changes in operating assets and liabilities increasing (decreasing) cash:			
Receivables	8,760	3,735	(19,061)
Inventories	61	307	(1,730)
Other current assets	20,827	(20,603)	12,374
Other assets and liabilities, net	(26,937)	14,271	(5,069)
Accounts payable and accrued expenses	(108,733)	41,165	75,299
Net cash provided by operating activities	311,559	579,189	357,452
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures for property, plant and equipment	(715,205)	(2,058,415)	(1,280,848)
Acquisitions of assets	(795,074)	—	(116,650)
Proceeds from sale of assets	263,220	158,781	9,034
Contributions on equity investments	—	(1,528)	—
Loans to equity investees	—	(7,500)	—
Refunds of restricted deposits	—	—	10,328
Fundings of restricted deposits	—	(781)	(7,445)
Net cash used in investing activities	(1,247,059)	(1,909,443)	(1,385,581)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from borrowings	2,619,607	3,252,209	1,331,541
Repayments of borrowings	(2,416,975)	(1,944,542)	(1,332,219)
Dividends paid-redeemable convertible preferred	—	(17,552)	(33,321)
Noncontrolling interest distributions	(26)	(5,497)	(144)
Proceeds from issuance of common stock	324,830	—	1,114,660
Proceeds from issuance of convertible perpetual preferred stock	443,210	—	—
Stock-based compensation excess tax benefit	(3,864)	4,594	—
Purchase of treasury stock	(5,747)	(3,553)	(1,661)
Debt issuance costs	(18,310)	(17,904)	(26,540)
Net cash provided by financing activities	942,725	1,267,755	1,052,316
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	7,225	(62,499)	24,187
CASH AND CASH EQUIVALENTS, beginning of year	636	63,135	38,948
CASH AND CASH EQUIVALENTS, end of year	$ 7,861	$ 636	$ 63,135
Supplemental Disclosure of Cash Flow Information:			
Cash paid for interest, net of amounts capitalized	$ 171,994	$ 131,183	$ 83,567
Cash paid for income taxes	2,908	2,191	2,371
Supplemental Disclosure of Noncash Investing and Financing Activities:			
Change in accrued capital expenditures	$ (70,063)	$ 119,432	$ —
Convertible perpetual preferred stock dividends payable	8,813	—	—
Redeemable convertible preferred stock dividends, net of dividends paid	—	—	8,956
Insurance premium financed	—	—	1,496
Accretion on redeemable convertible preferred stock	—	7,636	1,421

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

SandRidge Energy, Inc., and Subsidiaries
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. (including its subsidiaries, collectively, the "Company" or "SandRidge") is an independent natural gas and oil company concentrating on exploration, development and production activities. The Company also owns and operates natural gas gathering and treating facilities and carbon dioxide ("CO_2") treating and transportation facilities and has marketing and tertiary oil recovery operations. In addition, Lariat Services, Inc. ("Lariat"), a wholly owned subsidiary of the Company, owns and operates drilling rigs and a related oil field services business. The Company's primary exploration, development and production areas are concentrated in West Texas. The Company also operates interests in the Mid-Continent, the Cotton Valley Trend in East Texas, the Gulf Coast and the Gulf of Mexico.

Principles of Consolidation. The consolidated financial statements include the accounts of SandRidge Energy, Inc. and its wholly owned or majority owned subsidiaries and a variable interest entity for which the Company is the primary beneficiary. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications. Certain reclassifications have been made to prior period financial statements to conform to the current period presentation.

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of natural gas and oil reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company's control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, prevailing commodity prices, operating costs and other factors. These revisions may be material and could materially affect the Company's future depletion, depreciation and amortization expenses.

Risks and Uncertainties. The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for natural gas and oil, each of which depend on numerous factors beyond the Company's control such as economic conditions, regulatory developments and competition from other energy sources. The energy markets historically have been volatile and natural gas and oil prices in 2009 were substantially lower than in 2008 and 2007, and may be subject to significant fluctuations in the future. The Company's derivative arrangements serve to mitigate a portion of the effect of this price volatility on the Company's cash flows, and while derivative contracts for the majority of expected 2010, 2011 and 2012 oil production are in place, there are no fixed price swap contracts in place for the Company's natural gas production beyond 2010. See Note 14 for the Company's open natural gas and oil commodity derivative contracts. In addition, the Company will need to incur capital expenditures in 2010 in order to achieve production targets required to meet its commitments to deliver gas under certain gathering and treating arrangements. The Company is dependent on availability under its senior credit facility, along with cash flows from operating activities, to fund those capital expenditures. Based on anticipated natural gas and oil prices and availability under its senior credit facility, the Company expects to be able to fund its planned capital expenditures for 2010. However, a substantial or extended decline in natural gas and oil prices could have a material adverse effect on the

Company's financial position, results of operations, cash flows and quantities of natural gas and oil reserves that may be economically produced, and could impact the Company's ability to comply with the financial covenants under the senior credit facility, which in turn would limit further borrowings to fund capital expenditures. See Note 12 for discussion of the financial covenants.

Cash and Cash Equivalents. The Company considers all highly-liquid instruments with a maturity of three months or less when purchased to be cash equivalents as these instruments are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period.

Accounts Receivable, Net. The Company has receivables for sales of natural gas, oil and natural gas liquids, as well as receivables related to the exploration and treating services for natural gas, oil and natural gas liquids. Management has established an allowance for doubtful accounts. The allowance is evaluated by management and is based on management's review of the collectability of the receivables in light of historical experience, the nature and volume of the receivables and other subjective factors.

Inventories. Inventories consist of oil field services supplies and are stated at the lower of cost or market with cost determined on an average cost basis.

Investments. Investments in affiliated companies are accounted for under the equity method in circumstances where the Company is deemed to exercise significant influence over the operating and investing policies of the investee but does not have control. Under the equity method, the Company recognizes its share of the investee's earnings in its consolidated statements of operations. Investments in affiliated companies not accounted for under the equity method are accounted for under the cost method. See Note 7. Investments in marketable equity securities have been designated as available for sale and measured at fair value pursuant to the fair value option which requires unrealized gains and losses be reported in earnings.

Debt Issuance Costs. The Company amortizes debt issuance costs related to its long-term debt as interest expense over the scheduled maturity period of the debt. Unamortized debt issuance costs were $49.1 million as of December 31, 2009 and $38.2 million as of December 31, 2008. The Company includes these unamortized costs in other assets in its consolidated balance sheets.

Revenue Recognition and Gas Balancing. Natural gas and oil revenues are recorded when title passes to the customer, net of royalties, discounts and allowances, as applicable. The Company accounts for natural gas and oil production imbalances using the sales method, whereby the Company recognizes revenue on all natural gas and oil sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas and oil sold. Liabilities are recorded by the Company for imbalances greater than the Company's proportionate share of remaining estimated natural gas and oil reserves. The Company has recorded a liability for gas imbalance positions related to natural gas properties with insufficient proved reserves of $1.9 million and $1.7 million at December 31, 2009 and 2008, respectively. The Company includes the gas imbalance positions in other long-term obligations in its consolidated balance sheets.

The Company recognizes revenues and expenses generated from day work drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. The Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another are recognized over the term of the related drilling contract. The contract terms typically range from 20 to 90 days.

Midstream gas services are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. Consolidated midstream and marketing revenues represent natural gas sold on behalf of third parties and the fees the Company charges related to gathering, compressing and treating this gas. In general, natural gas purchased and sold by the midstream gas business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determined and collectability is reasonably assured.

Revenue from sales of CO_2 is recognized when the product is delivered to the customer. The Company recognizes service fees related to the transportation of CO_2 as revenue when the related service is provided.

Environmental Costs. Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. Environmental costs accrued at December 31, 2009 and 2008 were not material.

Natural Gas and Oil Operations. The Company uses the full cost method to account for its natural gas and oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool. These capitalized costs include costs of all unproved properties, internal costs directly related to the Company's acquisition, exploration and development activities and capitalized interest. During 2009, the Company capitalized internal costs of $22.3 million to the full cost pool, including $4.3 million of stock compensation. During 2008, the Company capitalized internal costs of $19.1 million to the full cost pool. The Company did not capitalize any interest expense to the full cost pool in 2009 or 2008. During 2007, the Company capitalized internal costs and interest expense of $4.6 million and $0.3 million, respectively, to the full cost pool. There was no stock compensation capitalized in 2008 or 2007.

Capitalized costs are amortized using a unit-of-production method. Under this method, the provision for depreciation, depletion and amortization is computed at the end of each quarter by multiplying total production for the quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the quarter.

Costs associated with unproved properties are excluded from the amortizable cost base until a determination has been made as to the existence of proved reserves. Unproved properties are reviewed at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subjected to amortization. Sales and abandonments of natural gas and oil properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved natural gas and oil reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the reserve quantities of a cost center.

Under the full cost method of accounting, total capitalized costs of natural gas and oil properties, net of accumulated depreciation, depletion and amortization, less related deferred income taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties, plus estimated salvage value, less the related tax effects (the "ceiling limitation"). A ceiling limitation calculation is performed at the end of each quarter. If total capitalized costs, net of accumulated depreciation, depletion and amortization, less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. See Note 8.

For year end December 31, 2009, the ceiling limitation calculation used a 12-month natural gas and oil average, as adjusted for basis or location differentials using a 12-month average, and held constant over the life of the reserves ("net wellhead prices"). For prior periods, the ceiling limitation calculation used natural gas and oil prices in effect as of the balance sheet date, as adjusted for basis or location differentials as of the balance sheet date, and held constant over the life of the reserves. If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of natural gas and oil. The Company may, from time-to-time, use derivative financial instruments to hedge against the volatility of natural gas and oil prices. Derivative contracts that qualify and are designated as cash flow hedges are included in estimated future cash flows. Historically, the Company has not designated any of its derivative contracts as cash flow hedges and has therefore not included its derivative contracts in estimating future cash flows. The future cash outflows associated with future development or abandonment of wells are included in the computation of the discounted present value of future net revenues for purposes of the ceiling limitation calculation.

The costs associated with unproved properties, initially excluded from the amortization base, relate to unproved leasehold acreage, wells and production facilities in progress and wells pending determination of the existence of proved reserves, together with capitalized interest costs for these projects. Unproved leasehold costs are transferred to the amortization base with the costs of drilling the related well once a determination of the existence of proved reserves has been made or upon impairment of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and completed wells that have yet to be evaluated are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry wells are transferred to the amortization base immediately upon determination that the well is unsuccessful.

All items classified as unproved property are assessed on a quarterly basis for possible impairment or reduction in value. Properties are assessed on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from 3 to 39 years.

Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are considered to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset including disposal value, if any, is less than the carrying amount of the asset. If any asset is considered impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value.

When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statements of operations.

Asset Retirement Obligation. The Company owns natural gas and oil properties that require expenditures to plug and abandon the wells when the natural gas and oil reserves in the wells are depleted. These expenditures are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired). Asset retirement obligations are recorded as a liability at their estimated present value at the asset's inception, with the offsetting increase to property cost. Periodic accretion expense of the estimated liability is recorded in the consolidated statements of operations.

Asset retirement obligations primarily represent the Company's estimate of fair value to plug, abandon and remediate the natural gas and oil properties at the end of their productive lives, in accordance with applicable state laws. The Company determines its asset retirement obligations by calculating the present value of estimated expenses related to the liability. Estimating the future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. Inherent in the present value calculation rates are the timing of settlement and changes in the legal, regulatory, environmental and political environments. The following shows the activity of the asset retirement obligation for the years ended December 31 (in thousands).

	2009	2008	2007
Asset retirement obligation, January 1	$ 84,772	$58,580	$45,216
Liability incurred upon acquiring and drilling wells	14,537	5,707	3,265
Revisions in estimated cash flows	10,831	15,976	5,971
Liability settled in current period	(6,111)	(764)	(9)
Accretion of discount expense	7,108	5,273	4,137
Asset retirement obligation, December 31	111,137	84,772	58,580
Less: current portion	2,553	275	864
Asset retirement obligation, net of current	$108,584	$84,497	$57,716

The revisions in estimated cash flows for 2009 and 2008 are primarily due to changes in reserve lives based on lower natural gas and oil prices used to determine reserves at December 31, 2009 and 2008. Due to hurricane damage, certain non-operated offshore platforms were plugged and abandoned during 2009 in advance of anticipated timelines.

Income Taxes. Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Deferred tax assets are reduced by a valuation allowance if a determination is made that it is more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence.

The Company has elected an accounting policy in which interest and penalties on income taxes are presented as a component of the income tax provision, rather than as a component of interest expense. Interest and penalties resulting from the underpayment of or the late payment of income taxes due to a taxing authority and interest and penalties accrued relating to income tax contingencies, if any, are presented, on a net of tax basis, as a component of the income tax provision.

Noncontrolling Interest. Effective January 1, 2009, the Company implemented the guidance in ASC Topic 810, Consolidation, which resulted in changes to the presentation for noncontrolling interests. Noncontrolling interest in the Company's subsidiaries represents ownership interests in the consolidated entity and is included as a component of equity in the consolidated balance sheets and consolidated statement of changes in equity as required by ASC Topic 810, Consolidation. All historical periods presented in the accompanying consolidated financial statements reflect these changes to the presentation for noncontrolling interests.

During October 2009, the Company executed amendments to certain agreements related to the ownership and operation of Grey Ranch Plant, LP ("GRLP"), the limited partnership that operates the Grey Ranch Plant located in Pecos County, Texas. As a result of these amendments, the Company became the primary beneficiary of GRLP. The Company began consolidating the activity of GRLP in its consolidated financial statements prospectively on the effective date of the amendments, or October 1, 2009. The 50% ownership interest not held by the Company is presented as noncontrolling interest on the consolidated financial statements at December 31, 2009.

At December 31, 2009, 2008 and 2007, noncontrolling interest in the Company's consolidated subsidiaries included a 1.29% interest in Cholla Pipeline, LP. At December 31, 2007, noncontrolling interest in the Company's consolidated subsidiaries also included a 26.19% interest in Sagebrush Pipeline, LLC ("Sagebrush"). As a result of the sale of Sagebrush's assets in May 2008, the noncontrolling interest in Sagebrush was distributed. See Note 2.

Concentration of Risk. The Company maintains cash balances at several financial institutions. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. From time to time, the Company may have balances in these accounts that exceed the federally insured limit. The Company does not anticipate any loss associated with balances in excess of the federally insured limit.

All of the Company's hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of the Company's hedging transactions have an "investment grade" credit rating. The Company monitors on an ongoing basis the credit ratings of its hedging counterparties and considers its counterparties' credit default risk rating in determining the fair value of its derivative contracts. The weighted average credit default swap rate for our counterparties was 0.3% and 2.3% at December 31, 2009 and 2008, respectively.

The purchasers of the Company's natural gas and oil production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. In 2009, 2008 and 2007, the Company had one individual purchaser accounting for 20.0%, 10.5% and 11.2%, respectively, of its total sales. The Company believes other purchasers are available in its areas of operations and does not believe the loss of any one of its purchasers would materially affect the Company's ability to sell the natural gas and oil it produces.

Fair Value of Financial Instruments. The Company's financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of these instruments. See Note 3 for discussion of the Company's derivative contracts and long-term debt.

Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in natural gas and oil prices, the Company enters into interest rate swaps and natural gas and oil derivative contracts.

The Company recognizes all of its derivative instruments as either assets or liabilities at fair value. The accounting for changes in the fair value (i.e., gains or losses) of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship, and further, on the type of hedging relationship. For those derivative instruments that are designated and qualify as hedging instruments, the Company designates the hedging instrument, based on the exposure being hedged, as either a fair value hedge or a cash flow hedge.

For derivative instruments not designated as hedging instruments, the gain or loss is recognized in current earnings during the period of change. None of the Company's derivatives was designated as hedging instruments during 2009, 2008 and 2007.

Stock-Based Compensation. ASC Topic 718, Compensation — Stock Compensation, establishes the accounting for equity instruments exchanged for employee services. Under ASC Topic 718, stock-based compensation cost is measured based on the calculated fair value of the award on the grant date. The expense is recognized on a straight-line basis over the employee's requisite service period, generally the vesting period of the award. The related excess tax benefit received upon exercise of stock options or vesting of restricted stock, if any, is reflected in the statement of cash flows as a financing activity. The related excess tax expense due upon exercise of stock options or vesting of restricted stock, if any, is reflected in the statement of cash flows as an operating activity.

Recently Adopted Accounting Pronouncements. In December 2007, the FASB issued new guidance establishing accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent's ownership interest and the valuation of retained noncontrolling equity investments when a subsidiary is deconsolidated. This new guidance, included in ASC Topic 810, Consolidation, also establishes disclosure requirements to clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. Effective January 1, 2009, the Company implemented the new guidance, which resulted in changes to the presentation for noncontrolling interests. This implementation did not have a material impact on the Company's financial position or results of operations. All historical periods presented in the accompanying consolidated financial statements reflect these changes to the presentation for noncontrolling interests. See Note 20.

In February 2008, the FASB issued guidance that delayed the effective date of certain requirements under ASC Topic 820, Fair Value Measurements and Disclosures, to fiscal years beginning after November 15, 2008 for all nonfinancial assets and liabilities except those recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. Effective January 1, 2009, the Company began following ASC Topic 820 for all nonfinancial assets and liabilities. This implementation did not have a material impact on the Company's financial position or results of operations.

In March 2008, the FASB issued new guidance regarding disclosures in ASC Topic 815, Derivatives and Hedging, which requires expanded disclosures to provide greater transparency about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedge items are accounted for under ASC Topic 815, and (iii) how derivative instruments and related hedged items affect an entity's financial position, results of operations and cash flows. ASC Topic 815 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments and disclosures about credit risk-related contingent features in derivative agreements. The new guidance regarding disclosures in ASC Topic 815 became effective for the Company on January 1, 2009 and did not have a material impact on its financial position or results of operations. See Note 14.

In April 2009, the FASB amended ASC Topic 825, Financial Instruments, to require publicly traded companies to provide disclosures about fair value of financial instruments in interim financial information as well as in annual financial statements. Under ASC Topic 825, entities must disclose, in the body or in the accompanying notes of its summarized financial information for interim reporting periods and in its financial statements for annual reporting periods, the fair value of all financial instruments for which it is practicable to estimate the value, whether or not recognized in the statement of financial position. The amendment to ASC Topic 825 became effective for the Company in the quarter ended June 30, 2009 and had no impact on the Company's financial position or results of operations. See Note 3.

In May 2009, the FASB issued guidance in ASC Topic 855, Subsequent Events, to establish general standards of accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or available to be issued. In particular, ASC Topic 855 sets forth the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements for both interim and annual financial statements. The Company has applied the provisions of ASC Topic 855 to its consolidated interim and annual financial statements for periods ended after June 15, 2009. See Note 22.

In June 2009, the FASB issued Accounting Standards Update 2009-01, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles — a replacement of FASB Statement No. 162" ("ASU 2009-01"). The FASB ASC is intended to be the source of authoritative GAAP and reporting standards as issued by the FASB. The primary purpose of the FASB ASC is to improve clarity and use of existing standards by grouping authoritative literature under common topics. ASU 2009-01 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Codification does not change or alter existing GAAP. The implementation of ASU 2009-01 had no impact to the Company's financial position or results of operations.

In January 2010, the FASB issued Accounting Standards Update 2010-03 ("ASU 2010-03") to align the oil and gas reserve estimation and disclosure requirements of ASC Topic 932, Extractive Industries — Oil and Gas, with the requirements in the Securities and Exchange Commission's final rule, *Modernization of the Oil and Gas Reporting Requirements,* which was issued on December 31, 2008 and was effective for the year ended December 31, 2009. The *Modernization of the Oil and Gas Reporting Requirements* was designed to modernize and update the oil and gas disclosure requirements to align with current practices and changes in technology. Key provisions of ASU 2010-03 are as follows:

The new rules require reserve estimates to be calculated using a 12-month average price. The 12-month average price is also required to be used for purposes of calculating the full cost ceiling limitations. Price changes can still be incorporated to the extent defined by contractual arrangements. The use of a 12-month average price rather than a single-day price is intended to reduce the impact on reserve estimates and the full cost ceiling limitations due to short-term volatility and seasonality of prices.

The new rules amend the definition of lowest known hydrocarbon to permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. Also included in the new rules are provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations.

The new rules also amend the definition of proved oil and gas reserves to include reserves located beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty. This is designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells, was established.

The new rules permit disclosure of probable and possible reserves and provide definitions of probable reserves and possible reserves. Disclosure of probable and possible reserves is optional. However, such disclosure must meet specific requirements. Disclosures of probable and possible reserves must provide the same level of geographical detail as proved reserves and must state whether the reserves are developed or undeveloped. Probable and possible reserve disclosures must also provide the relative uncertainty associated with these classifications of reserves estimations.

The new rules require disclosure of additional details on proved undeveloped reserves, including the total quantity of proved undeveloped reserves at year end, any material changes to proved undeveloped reserves that occurred during the year, investments and progress made to convert proved undeveloped reserves to developed oil and gas reserves and an explanation of the reasons why concentrations of proved undeveloped reserves in individual fields or countries have remained undeveloped for five years or more after disclosure as proved undeveloped reserves.

The new rules require the qualifications and measures taken to assure the independence and objectivity of any business entity or employee primarily responsible for preparing or auditing the reserve estimates be reported.

The Company implemented ASU 2010-03 prospectively as a change in accounting principle inseparable from a change in accounting estimate at December 31, 2009. The Company has not determined reserve levels at December 31, 2009 under the previous accounting rules due to the operational and technical challenges of preparing reserve reports under two sets of rules and therefore it is not practicable to determine the impact of adopting this accounting principle.

Recently Issued Accounting Principles Not Yet Adopted. In December 2009, the FASB issued Accounting Standards Update 2009-16, "Transfers and Servicing — Accounting for Transfers of Financial Assets," ("ASU 2009-16") which codifies FASB Statement No. 166, "Accounting for Transfers of Financial Assets, an amendment of FASB Statement No. 140". ASU 2009-16, among other things, eliminates the concept of a "qualifying special-purpose entity," changes the requirements for derecognizing financial assets, and requires additional disclosures about transfers of financial assets. ASU 2009-16 is effective for annual reporting periods beginning after November 15, 2009. ASU 2009-16 is not anticipated to impact the Company's financial position or results of operations.

In December 2009, the FASB issued Accounting Standards Update 2009-17, "Consolidations — Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities" ("ASU 2009-17"), which codifies FASB Statement No. 167, "Amendments to FASB Interpretation No. 46(R)". ASU 2009-17 represents a revision to former FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities," ("FIN 46(R)") and changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting or similar rights should be consolidated. ASU 2009-17 also requires enhanced disclosures about a reporting entity's involvement with variable interest entities. ASU 2009-17 is effective for annual reporting periods beginning after November 15, 2009. The implementation of ASU 2009-17 is not anticipated to impact the Company's financial position or results of operations.

In January 2010, the FASB issued Accounting Standards Update 2010-06, "Fair Value Measurements and Disclosures: Improving Disclosures about Fair Value Measurements" ("ASU 2010-06"). ASU 2010-06 requires additional disclosures and clarifies existing disclosure requirements about fair value measurement as set forth in ASC Topic 820. ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009, except for certain disclosure requirements regarding activity in Level 3 fair value measurements which is effective for fiscal years beginning after December 15, 2010. The implementation of ASU 2010-06 is expected to have no impact on the Company's results of operations or financial condition, but will require additional disclosure.

2. Acquisitions and Dispositions

2007 Acquisitions

The Company closed the following acquisitions in 2007:

- In October 2007, the Company purchased developed and undeveloped properties located in West Texas from an oil and gas company. The purchase price was approximately $73.8 million, comprised of

$25.0 million in cash and a $48.8 million note payable. The $25.0 million cash consideration paid was funded through a draw on the Company's senior credit facility. All principal and accrued interest (accruing at 7% annually) due on the note payable were repaid in November 2007 with proceeds from the Company's initial public offering of its common stock. For additional discussion of the Company's initial public offering, refer to Note 20 herein.

- In November 2007, the Company purchased a gas treatment plant and related gathering system located in Pecos County, Texas. The purchase price of approximately $10.0 million was paid in cash.
- In November 2007, the Company purchased leasehold acreage and producing well interests located predominantly in the West Texas Overthrust ("WTO") from a group of entities controlled by a significant shareholder. The purchase price of approximately $32.0 million was paid in cash.

2008 Acquisitions and Dispositions

The Company closed the following acquisitions and dispositions in 2008:

- In May 2008, the Company sold all of its assets located in the Piceance Basin of Colorado. Assets sold included undeveloped acreage, working interests in wells, gathering and compression systems and other facilities related to the wells. Net proceeds to the Company were approximately $147.2 million after closing adjustments. The portion of the Company's net proceeds attributable to the disposed gathering and compression systems and facilities exceeded the book basis of those assets resulting in a gain on sale of approximately $7.2 million after closing adjustments. The sale of the acreage and working interests in wells was accounted for as an adjustment to the full cost pool with no gain or loss recognized.
- In July 2008, the Company purchased land, minerals, developed and undeveloped leasehold and interests in producing properties through various transactions for an aggregate purchase price of $67.6 million, which was paid in cash.
- In October 2008, the Company purchased certain working interests and related reserves in Company wells owned by the Company's Chairman and Chief Executive Officer and certain of his affiliates. The purchase price of approximately $67.3 million, after closing adjustments, was paid in cash.

2009 Acquisitions and Dispositions

The Company closed the following acquisitions and dispositions in 2009:

- In June 2009, the Company completed the sale of its gathering and compression assets located in the Piñon Field, part of the WTO located in Pecos and Terrell counties, Texas. Net proceeds to the Company were approximately $197.5 million, resulting in a loss of $26.1 million. In conjunction with the sale, the Company entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, the Company has dedicated its Piñon Field acreage for priority gathering services for a period of 20 years and the Company will pay a fee that was negotiated at arms' length for such services. Pursuant to the operations and maintenance agreement, the Company will operate and maintain the gathering system assets sold for a period of 20 years unless the Company or the buyer of the assets chooses to terminate the agreement.
- In June 2009, the Company completed the sale of its drilling rights in East Texas below the depth of the Cotton Valley formation for net proceeds of $57.2 million, after certain post-closing adjustments. In October 2009, the Company received an additional $1.3 million in proceeds as a result of the post-closing adjustments. The sale of the drilling rights was accounted for as an adjustment to the full cost pool with no gain or loss recognized by the Company.

- In December 2009, the Company purchased developed and undeveloped natural gas and oil properties located in the Permian Basin from Forest Oil Corporation and one of its subsidiaries (collectively, "Forest"). The purchase price was $800.0 million, subject to purchase price and post-closing adjustments. The acquisition was financed with proceeds from the issuance of $450.0 million of 8.75% Senior Notes due 2020, the placement of $200.0 million of new shares of 6.0% convertible perpetual preferred stock, and a public offering of the Company's common stock for $226.6 million. See further discussion at Note 12 and Note 20.

  The acquisition qualifies as a business combination and, as such, the Company estimated the fair value of this property as of the December 21, 2009 acquisition date, the date on which the acquirer obtained control of the properties. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs.

  The Company estimates the fair value of these properties approximates the consideration paid to Forest, which the Company concludes approximates the fair value that would be paid by a typical market participant. This measurement resulted in no goodwill being recognized. The acquisition-related costs totaling $0.3 million have been expensed as incurred in general and administrative expense on the consolidated income statement. Revenues of $3.6 million and earnings of $2.8 million generated by the acquired properties from December 21, 2009 to December 31, 2009 have been included in the accompanying consolidated statements of operations.

  The following table summarizes the consideration paid to Forest and the amounts of the assets acquired and liabilities assumed as of December 21, 2009. The purchase price allocation is preliminary and subject to adjustment as the final closing settlement will be completed during mid 2010.

	(In thousands)
Consideration paid to Forest:	
Cash, net of accrued purchase price adjustment	$795,074
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed and undeveloped properties	754,185
Unproved leasehold properties	52,246
Asset retirement obligation	(11,357)
Total identifiable net assets	$795,074

Pro Forma Information — Forest Acquisition

The unaudited financial information in the table below summarizes the combined results of the Company's operations and the properties acquired from Forest, on a pro forma basis, as though the purchase had taken place at the beginning of each period presented. The pro forma information is based on the Company's consolidated results of operations for the years ended December 31, 2009 and 2008, on historical results of the properties acquired, and on estimates of the effect of the transactions to the combined results. The pro forma information is not necessarily indicative of results that actually would have occurred had the transaction been in effect for the periods indicated, or of results that may occur in the future.

	Year Ended December 31,			
	2009		2008	
	Actual	Pro Forma	Actual	Pro Forma
	(in thousands, except per share data)			
		(Unaudited)		(Unaudited)
Revenues	$ 591,044	$ 682,593	$ 1,181,814	$ 1,373,834
Net loss applicable to SandRidge Energy, Inc., common stockholders	$(1,784,403)	$(1,949,567)	$(1,457,512)	$(1,699,728)
Basic and diluted earnings per share available to SandRidge Energy, Inc., common stockholders:				
Net loss applicable to SandRidge Energy, Inc., common stockholders	$ (10.20)	$ (9.72)	$ (9.36)	$ (9.38)

Crusader Acquisition

In September 2009, the Company entered into a Stock Purchase Agreement (the "Crusader Purchase Agreement") with Crusader Energy Group Inc., and its subsidiaries (collectively, "Crusader") to purchase all of the shares of common stock of Crusader that were to be issued upon the effectiveness of Crusader's reorganization under Chapter 11 of the United States Bankruptcy Code. On November 12, 2009, the Company announced its withdrawal from the acquisition process of Crusader as permitted under the bidding procedures applicable to Crusader's bankruptcy. On December 14, 2009, the Company terminated the Crusader Purchase Agreement, and on December 31, 2009, the Company received the break-up fee of $7.0 million provided for in the Crusader Purchase Agreement.

3. Fair Value Measurements

The Company applies the guidance provided under ASC Topic 820, Fair Value Measurements and Disclosures, to its financial assets and liabilities and nonfinancial liabilities that are measured and reported on a fair value basis. Pursuant to this guidance, the Company has classified and disclosed its fair value measurements using the following levels of the fair value hierarchy:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3: Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels as described in ASC Topic 820. The determination of the fair values, stated below, takes into account the market for the Company's financial assets and liabilities, the associated credit risk and other factors as required by ASC Topic 820. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 1 Fair Value Measurements

Other long-term assets. The fair value of other long-term assets, consisting of assets attributable to the Company's deferred compensation plan, is based on quoted market prices.

Level 3 Fair Value Measurements

Derivative Contracts The fair values of the Company's natural gas, oil and interest rate swaps are based upon quotes obtained from counterparties to the derivative contracts. The Company reviews other readily available market prices for its derivative contracts as there is an active market for these contracts. However, the Company does not have access to the specific valuation models used by its counterparties or other market participants. Included in these models are discount factors that the Company must estimate in its calculation. Additionally, the Company applies a value weighted average credit default risk rating factor for its counterparties in determining the fair value of its derivative contracts. Based on the inputs for the fair value measurement, the Company classified its derivative contract assets and liabilities as Level 3.

The following table summarizes the Company's financial assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy as of December 31, 2009 (in thousands):

	Fair Value Measurements			Assets / Liabilities at Fair Value
Description	**Level 1**	**Level 2**	**Level 3**	
Derivative contracts — assets	$ —	$—	$105,994	$105,994
Derivative contracts — liabilities	—	—	(68,140)	(68,140)
Other long-term assets	6,251	—	—	6,251
	$6,251	$—	$ 37,854	$ 44,105

The table below sets forth a reconciliation of the Company's financial assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the year ended December 31, 2009 (in thousands):

	Derivatives
Balance of Level 3, December 31, 2008	$ 237,903
Total gains or losses (realized/unrealized)	141,744
Purchases, issuances and settlements	(341,793)
Transfers in and out of Level 3	—
Balance of Level 3, December 31, 2009	$ 37,854
Changes in unrealized gains (losses) on derivative contracts held as of December 31, 2009	$(200,049)

See Note 14 for further discussion of the Company's derivative contracts.

Fair Value of Debt

The Company measures fair value of its long-term debt based on quoted market prices and with consideration given to the effect of the Company's credit risk. The estimated fair value of the Company's senior notes and the carrying value at December 31, 2009 were as follows (in thousands):

	Fair Value	Carrying Value
Senior Floating Rate Notes due 2014	$316,859	$350,000
8.625% Senior Notes due 2015	655,470	650,000
9.875% Senior Notes due 2016(1)	390,692	351,021
8.0% Senior Notes due 2018	739,778	750,000
8.75% Senior Notes due 2020(2)	451,890	442,590

(1) Carrying value is net of a $14,479 discount.
(2) Carrying value is net of a $7,410 discount.

The carrying value for the Company's senior credit facility and remaining fixed rate debt instruments approximate fair value based on current rates applicable to similar instruments. See Note 12 for further discussion of the Company's long-term debt.

4. Accounts Receivable

A summary of trade accounts receivable is as follows (in thousands):

	December 31,	
	2009	2008
Natural gas and oil sales	$ 82,472	$ 72,266
Natural gas and oil services	10,484	20,476
Joint interest billing	10,101	13,816
Other	5,945	62
	109,002	106,620
Less allowance for doubtful accounts	(3,590)	(3,874)
Total trade accounts receivable, net	$105,412	$102,746

The following table shows the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	2009	2008	2007
Allowance for doubtful accounts, January 1	$3,874	$2,238	$3,025
Additions charged to costs and expenses	214	1,748	—
Deductions(1)	(498)	(112)	(787)
Allowance for doubtful accounts, December 31	$3,590	$3,874	$2,238

(1) Deductions represent write-off of receivables.

The Company's customer, SemGroup, L.P. and certain of its subsidiaries (collectively, "SemGroup"), filed for bankruptcy on July 22, 2008. During 2008, the Company established an allowance in the amount of $1.5 million for all amounts due from SemGroup.

5. Other Current Assets

Other current assets consist of the following (in thousands):

	December 31, 2009	December 31, 2008
Prepaid insurance	$ 7,627	$ 9,374
Deposits	7,499	26,806
Prepaid drilling	1,804	2,657
Other	3,650	2,570
Total other current assets	$20,580	$41,407

6. Property, Plant and Equipment

Property, plant and equipment consist of the following (in thousands):

	December 31, 2009	December 31, 2008
Natural gas and oil properties:		
Proved	$ 5,913,408	$ 4,676,072
Unproved	281,811	215,698
Total natural gas and oil properties	6,195,219	4,891,770
Less accumulated depreciation, depletion and impairment(1)	(4,223,437)	(2,369,840)
Net natural gas and oil properties capitalized costs	1,971,782	2,521,930
Land	13,937	11,250
Non natural gas and oil equipment(2)	594,132	764,792
Buildings and structures	78,584	71,859
Total	686,653	847,901
Less accumulated depreciation, depletion and amortization	(224,792)	(194,272)
Net capitalized costs	461,861	653,629
Total property, plant and equipment	$ 2,433,643	$ 3,175,559

(1) Includes cumulative full cost ceiling limitation impairment charges of $3,548.3 million and $1,855.0 million at December 31, 2009 and 2008, respectively. See Note 8.

(2) Includes capitalized interest of approximately $3.8 million at both December 31, 2009 and 2008.

In June 2009, the Company completed the sale of its gathering and compression assets located in the Piñon Field and the sale of its deep drilling rights in East Texas. In May 2008, the Company completed the sale of all its assets located in the Piceance Basin of Colorado. See Note 2.

The average rates used for depreciation and depletion of natural gas and oil properties were $1.68 per Mcfe in 2009 and $2.87 per Mcfe in 2008.

Costs Excluded from Amortization

Costs associated with unproved properties of $281.8 million as of December 31, 2009 were excluded from amounts subject to amortization. The following table summarizes the costs related to unproved properties which have been excluded from natural gas and oil properties being amortized at December 31, 2009 and the year in which they were incurred (in thousands):

	Year Cost Incurred				Excluded Costs at December 31, 2009
	2006	2007	2008	2009	
Property acquisition	$175,369	$—	$34,714	$65,125	$275,208
Exploration	—	—	—	6,603	6,603
Development	—	—	—	—	—
Capitalized interest	—	—	—	—	—
Total costs incurred	$175,369	$—	$34,714	$71,728	$281,811

The Company expects to complete the majority of the evaluation activities within six years from the applicable date of acquisition, contingent on the Company's capital expenditures and drilling program. In addition, the Company's internal engineers evaluate all properties on at least an annual basis.

7. Investments

During 2009, the Company had the following investments it accounted for under the equity method.

Grey Ranch, L.P. GRLP is a limited partnership that operates the Grey Ranch Plant located in Pecos County, Texas. The Company has long-term operating and gathering agreements with GRLP. The Company purchased its 50% ownership in GRLP during 2003. Income or losses of GRLP are allocated to the partners based on their ownership percentage. Any operating or cash shortfalls for GRLP require contributions from the partners. During October 2009, the Company executed amendments to certain agreements related to the ownership and operation of GRLP. As a result of these amendments, the Company became the primary beneficiary of GRLP. The Company previously accounted for its ownership interest in GRLP using the equity method of accounting; however, due to this change, the Company began consolidating the activity of GRLP in its consolidated financial statements prospectively beginning on the effective date of the amendments, October 1, 2009. The change from equity method accounting to the consolidation of GRLP activity had no effect on the Company's net income. The ownership interest not held by the Company is presented as noncontrolling interest in the consolidated financial statements. As of December 31, 2009, the Company's consolidated balance sheet included $16.0 million of net property, plant and equipment and $10.0 million of noncontrolling interest related to GRLP. Although GRLP is included in the Company's consolidated financial statements, the Company's interest in GRLP's assets is limited to its 50% ownership. GRLP's creditors have no recourse to the general credit of the Company.

At December 31, 2008, the Company's investment in GRLP was accounted for under the equity method. The Company's 50% ownership in GRLP totaled approximately $6.1 million and was classified as an investment in the accompanying consolidated balance sheets at December 31, 2008.

Larclay, L.P. Until April 15, 2009, Lariat and its partner Clayton Williams Energy, Inc. ("CWEI"), each owned a 50% interest in Larclay L.P. ("Larclay"), a limited partnership formed in 2006 to acquire drilling rigs and provide land drilling services, and, until such time, Lariat operated the rigs owned by Larclay. On April 15, 2009, Lariat completed an assignment to CWEI of Lariat's 50% equity interest in Larclay pursuant to the terms of an Assignment and Assumption Agreement (the "Larclay Assignment") entered into between Lariat and CWEI on March 13, 2009. Pursuant to the Larclay Assignment, Lariat assigned all of its right, title and interest in and to Larclay to CWEI effective April 15, 2009 and CWEI assumed all of the obligations and liabilities of Lariat relating to Larclay. The Company fully impaired both the investment in and notes receivable due from Larclay at December 31, 2008. See Note 8 for discussion of this impairment. There were no additional losses on Larclay during the year ended December 31, 2009 or as a result of the Larclay Assignment.

8. Impairment

Full Cost Ceiling Limitation. Under the full cost method of accounting, the net book value of natural gas and oil properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling limitation is the discounted estimated after-tax future net revenue from proved natural gas and oil properties, excluding future cash outflows associated with settling asset retirement obligations included in the net book value of natural gas and oil properties, plus the cost of properties not subject to amortization. In calculating future net revenues for the year ended December 31, 2009, prices and costs used are based on the most recent 12-month average. Prior to December 31, 2009, prices and costs used to calculate future net revenues were based on prices on the last day of the period. These prices are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. The Company has entered into various commodity derivative contracts; however, these derivative contracts are not accounted for as cash flow hedges. Accordingly, the effect of these derivative contracts has not been considered in calculating the full cost ceiling limitation.

The net book value, less related deferred tax liabilities, is compared to the ceiling limitation on both a quarterly and annual basis. Any excess of the net book value, less related deferred taxes, is written off as an expense. An expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and oil prices may have increased the ceiling limitation in the subsequent period. During the first quarter and the fourth quarter of 2009, the Company reduced the carrying value of its natural gas and oil properties by $1,304.4 million and $388.9 million, respectively, due to a full cost ceiling limitation. Due to the Company's full valuation allowance, there was no tax effect on the full cost ceiling impairments taken in 2009. During the fourth quarter of 2008, the Company reduced the carrying value of its oil and gas properties by $1,855.0 million due to a full cost ceiling limitation. The after-tax effect of this reduction in 2008 was $1,677.5 million.

Other Property, Plant and Equipment. The Company recorded a $10.0 million impairment in the fourth quarter of 2009 on its spare parts inventory due to a decline in market value. The inventory was classified as fixed assets due to the Company's intent to place the parts into service in the future. Also in the fourth quarter of 2009, the Company recorded a $3.9 million impairment on three buildings located on its downtown Oklahoma City campus. The Company has determined these buildings will not have use or value in the future.

Larclay, L.P. During 2008, Larclay experienced cash shortfalls as a result of its principal payments due pursuant to its rig loan agreement. As permitted under the Larclay partnership agreement, Lariat provided loans to Larclay to offset the cash shortfalls. At December 31, 2008, the notes outstanding to Larclay and related interest receivable were $7.5 million and $0.2 million, respectively. With the significant decline in natural gas and oil prices in the fourth quarter of 2008, the demand for Larclay's drilling rigs and land drilling services has decreased. Due to economic conditions, natural gas and oil prices and the continued cash shortfalls for Larclay, Lariat fully impaired its $4.8 million investment in Larclay, as well as notes and accrued interest receivable due from Larclay totaling $7.7 million, as of December 31, 2008. This resulted in an impairment expense of approximately $12.5 million included in the consolidated statement of operations for the year ended December 31, 2008.

9. Restricted Deposits

Restricted deposits represent bank trust and escrow accounts required by the Minerals Management Service of the United States Department of the Interior, surety bond underwriters, purchase agreements or other settlement agreements to satisfy the Company's eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. During 2008, the Company deposited $0.8 million in escrow accounts. There were no deposits to the escrow accounts in 2009.

10. Accounts Payable and Accrued Expenses

Trade accounts payable and accrued expenses consist of the following (in thousands):

	December 31,	
	2009	2008
Accounts payable	$134,212	$302,407
Convertible perpetual preferred stock dividends	8,813	—
Payroll and benefits	18,270	20,703
Drilling advances	4,985	4,074
Settlement agreement — current (See Note 13)	5,000	5,000
Accrued interest	31,382	26,790
Other	386	7,363
Total trade accounts payable and accrued expenses	$203,048	$366,337

11. Costs in Excess of Billings (Billings in Excess of Costs Incurred)

In June 2008, the Company entered into an agreement with a subsidiary of Occidental Petroleum Corporation ("Occidental") to construct and sell a CO_2 treating plant in Pecos County, Texas (the "Century Plant") and associated compression and pipeline facilities for $800.0 million. Under this agreement, the Company will construct the Century Plant and Occidental will pay a minimum of 100% of the contract price, plus any subsequent agreed-upon revisions, to the Company through periodic cost reimbursements based upon the percentage of the project completed by the Company. The Century Plant is expected to be completed in two phases with the start-up of Phase I expected in mid 2010. Upon start-up, the Century Plant will be owned and operated by Occidental for the purpose of separating and removing CO_2 from natural gas delivered by the Company. Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, Occidental will remove CO_2 from the Company's delivered production volumes. See Note 18 for discussion of gas volume requirements. The Company will retain all methane gas from the Century Plant.

The Company accounts for construction of the Century Plant using the completed-contract method, under which contract revenues and costs are recognized when work under the contract is completed or substantially completed. In the interim, costs incurred on and billings related to contracts in process are accumulated on the balance sheet. Contract gains or losses will be recorded, as development costs within the Company's natural gas and oil properties as part of the full cost pool, when it is determined that a gain or loss will be incurred. At December 31, 2009 and 2008, no amounts had been recorded to the full cost pool in anticipation of probable and estimable gains or losses. Costs in excess of billings were $12.3 million and were reported as a current asset in the accompanying consolidated balance sheet at December 31, 2009. Billings in excess of costs incurred were $14.1 million and were reported as a current liability in the accompanying consolidated balance sheet at December 31, 2008.

12. Long-Term Debt

Long-term obligations consist of the following (in thousands):

	December 31, 2009	December 31, 2008
Senior credit facility	$ —	$ 573,457
Other notes payable:		
Drilling rig fleet and related oil field services equipment	17,375	33,030
Mortgage	17,952	18,829
Senior Floating Rate Notes due 2014	350,000	350,000
8.625% Senior Notes due 2015	650,000	650,000
9.875% Senior Notes due 2016, net of $14,479 discount	351,021	—
8.0% Senior Notes due 2018	750,000	750,000
8.75% Senior Notes due 2020, net of $7,410 discount	442,590	—
Total debt	2,578,938	2,375,316
Less: Current maturities of long-term debt	12,003	16,532
Long-term debt	$2,566,935	$2,358,784

Senior Credit Facility. The amount the Company can borrow under its senior secured revolving credit facility (the "senior credit facility") is limited to a borrowing base, which was $850.4 million at December 31, 2009. The senior credit facility matures on November 21, 2011 and is available to be drawn on subject to limitations based on its terms and certain financial covenants, as described below.

The senior credit facility contains various covenants that limit the ability of the Company and certain of its subsidiaries to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets. Additionally, the senior credit facility limits the ability of the Company and certain of its subsidiaries to incur additional indebtedness with certain exceptions, including under the series of senior notes discussed below.

The senior credit facility contains financial covenants, including maintaining agreed levels for the (i) ratio of total funded debt to EBITDAX (as defined in the senior credit facility), which may not exceed 4.5:1.0 at each quarter end calculated using the last four completed fiscal quarters, (ii) ratio of EBITDAX to interest expense plus current maturities of long-term debt, which must be at least 2.5:1.0 at each quarter end calculated using the last four completed fiscal quarters, and (iii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. In the current ratio calculation (as defined in the senior credit facility) any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company's derivative contracts are disregarded. As of and during the year ended December 31, 2009, the Company was in compliance with all of the financial covenants under the senior credit facility.

The obligations under the senior credit facility are guaranteed by certain Company subsidiaries and are secured by first priority liens on all shares of capital stock of each of the Company's material present and future subsidiaries; all intercompany debt of the Company; and substantially all of the Company's assets, including proved natural gas and oil reserves representing at least 80% of the discounted present value (as defined in the senior credit facility) of proved natural gas and oil reserves reviewed in determining the borrowing base for the senior credit facility.

At the Company's election, interest under the senior credit facility is determined by reference to (a) the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 2.00% and 3.00% per annum or (b) the 'base rate,' which is the higher of (i) the federal funds rate plus 0.5%, (ii) the prime rate published by Bank of America or (iii) the Eurodollar rate (as defined in the senior credit facility) plus 1.00% per annum, plus, in each case under scenario (b), an applicable margin between 1.00% and 2.00% per annum. Interest is payable quarterly for prime rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest is paid at the end of each three-month period. The average annual interest rate paid on amounts outstanding under the senior credit facility was 2.33% for the year ended December 31, 2009.

Borrowings under the senior credit facility may not exceed the lower of the borrowing base or the committed amount. Private placements of senior notes totaling $365.5 million in May 2009 and $450.0 million in December 2009, discussed below, reduced the borrowing base to $850.4 million at December 31, 2009. The Company's borrowing base is redetermined in April and October of each year. With respect to each redetermination, the administrative agent and the lenders under the senior credit facility consider several factors, including the Company's proved reserves and projected cash requirements, and make assumptions regarding, among other things, natural gas and oil prices and production. Accordingly, the Company's ability to develop its properties and changes in commodity prices impact the borrowing base. No changes were made to the borrowing base during 2009 as a result of redeterminations. The Company has, at times, incurred additional costs related to the senior credit facility as a result of changes to the borrowing base. During 2009, additional costs of approximately $0.9 million were incurred. These costs have been deferred and are included in other assets in the accompanying consolidated balance sheets. At December 31, 2009, the Company had no amounts outstanding under the senior credit facility and $47.0 million in outstanding letters of credit, which affect the availability under the senior credit facility on a dollar-for-dollar basis.

On October 3, 2008, Lehman Brothers Commodity Services, Inc. ("Lehman Brothers"), a lender under the Company's senior credit facility, filed for bankruptcy. At the time that its parent, Lehman Brothers Holdings Inc., declared bankruptcy on September 15, 2008, Lehman Brothers elected not to fund its pro rata share, or 0.29%, of borrowings requested by the Company under the senior credit facility. Accordingly, the Company anticipates that Lehman Brothers will not fund its pro rata share of any future borrowing requests. The Company currently does not expect this reduced availability of amounts under the senior credit facility to impact its liquidity or business operations.

Other Notes Payable. The Company has financed a portion of its drilling rig fleet and related oil field services equipment through the issuance of notes secured by such equipment. At December 31, 2009, the aggregate outstanding balance of these notes was $17.4 million, with annual fixed interest rates ranging from 7.64% to 8.67%. The notes have a final maturity date of December 1, 2011 and require aggregate monthly installments of principal and interest in the amount of $0.8 million. The notes have a prepayment penalty (currently ranging from 0.50% to 1.00%) that is triggered if the Company repays the notes prior to maturity.

The debt incurred to purchase the downtown Oklahoma City property that serves as the Company's corporate headquarters is fully secured by a mortgage on one of the buildings and a parking garage located on the property. The note underlying the mortgage bears interest at 6.08% annually and matures on November 15, 2022. Payments of principal and interest in the amount of approximately $0.5 million are due on a quarterly basis through the maturity date. During 2009, the Company made payments of principal and interest on this note totaling $0.9 million and $1.1 million, respectively.

Senior Floating Rate Notes Due 2014 and 8.625% Senior Notes Due 2015. In May 2008, the Company exchanged senior term loans for senior unsecured notes with registration rights which were subsequently exchanged for substantially identical notes pursuant to a registered exchange offer. The effect of the exchange offers resulted in the Company issuing $350.0 million of Senior Floating Rate Notes due 2014 (the "Senior Floating Rate Notes") in exchange for the total outstanding principal amount of its senior floating rate term loan and $650.0 million of 8.625% Senior Notes due 2015 (the "8.625% Senior Notes") in exchange for the total outstanding principal amount of its 8.625% senior term loan. Terms of these senior notes are substantially identical to those of the exchanged senior term loans and the terms of the unregistered notes for which the senior term loans were exchanged. These senior notes are jointly and severally, unconditionally guaranteed on an unsecured basis by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries. See Note 24 for condensed consolidating financial information of the subsidiary guarantors.

The Senior Floating Rate Notes bear interest at LIBOR plus 3.625% (3.91% at December 31, 2009), except for the period from April 1, 2008 to June 30, 2008, for which the interest rate was 6.323%. Interest is payable quarterly with principal due on April 1, 2014. The average interest rate paid on outstanding Senior Floating Rate Notes for the year ended December 31, 2009 was 4.57% without consideration of the interest rate swap discussed below. The 8.625% Senior Notes bear interest at a fixed rate of 8.625% per annum with the principal due on April 1, 2015. Under the terms of the 8.625% Senior Notes, interest is payable semi-annually and, through the interest payment due on April 1, 2011, interest may be paid, at the Company's option, either entirely in cash or entirely with additional fixed rate senior notes. If the Company elects to pay the interest due during any period in additional fixed rate senior notes, the interest rate will increase to 9.375% during that period. All interest payments made to date on the 8.625% Senior Notes have been paid in cash.

In January 2008, the Company entered into a $350.0 million notional interest rate swap agreement to fix the variable LIBOR interest rate on the floating rate senior term loan for the period from April 1, 2008 to April 1, 2011. As a result of the exchange of the floating rate senior term loan to Senior Floating Rate Notes, the interest rate swap is now used to fix the variable LIBOR interest rate on the Senior Floating Rate Notes at an annual rate of 6.26% through April 1, 2011. In May 2009, the Company entered into a $350.0 million notional interest rate swap agreement to fix the variable LIBOR interest rate on the Senior Floating Rate Notes at an annual rate of 6.69% for the period from April 1, 2011 to April 1, 2013. The two interest rate swaps effectively serve to fix the Company's variable interest rate on its Senior Floating Rate Notes for the majority of the term of these notes. These swaps have not been designated as hedges.

The Company may redeem, at specified redemption prices, some or all of the Senior Floating Rate Notes at any time and some or all of the 8.625% Senior Notes on or after April 1, 2011.

The Company incurred $26.1 million of debt issuance costs in connection with the senior term loans. As the senior term loans were exchanged for unsecured senior notes with substantially identical terms, the remaining unamortized debt issuance costs on the senior term loans are being amortized over the terms of the Senior Floating Rate Notes and the 8.625% Senior Notes. These costs are included in other assets in the consolidated balance sheets.

9.875% Senior Notes Due 2016. In May 2009, the Company completed a private placement of $365.5 million of unsecured 9.875% Senior Notes due 2016 (the "9.875% Senior Notes") to qualified institutional investors eligible under Rule 144A of the Securities Act of 1933, as amended (the "Securities Act"). These notes were issued at a discount which will be amortized into interest expense over the term of the notes. Net proceeds from the offering were approximately $342.1 million after deducting offering expenses. The Company used the net proceeds from the offering to repay outstanding borrowings under the senior credit facility and for general corporate purposes. The notes bear interest at a fixed rate of 9.875% per annum, payable semi-annually, with the principal due on May 15, 2016. The 9.875% Senior Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices. The notes are jointly and severally, unconditionally guaranteed on an unsecured basis by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries.

In conjunction with the issuance of the 9.875% Senior Notes, the Company entered into a Registration Rights Agreement requiring the Company to register these notes by May 16, 2010 if they are not already freely tradable at that time. The Company is required to pay additional interest if it fails to fulfill its obligations under the agreement within the specified time periods.

Debt issuance costs of $7.9 million incurred in connection with the offering of the 9.875% Senior Notes are included in other assets in the consolidated balance sheet and are being amortized over the term of the notes.

8.0% Senior Notes Due 2018. In May 2008, the Company issued $750.0 million of unsecured 8.0% Senior Notes due 2018 (the "8.0% Senior Notes") to qualified institutional investors eligible under Rule 144A of the Securities Act. Net proceeds from the offering of approximately $734.0 million, after deducting offering expenses, were used to repay amounts outstanding under the senior credit facility and to fund a portion of the 2008 capital expenditure program. The notes bear interest at a fixed rate of 8.0% per annum, payable semi-annually, with the principal due on June 1, 2018. The notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices. The 8.0% Senior Notes are jointly and severally, unconditionally guaranteed on an unsecured basis, by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries. The notes are freely tradable.

The Company incurred $16.0 million of debt issuance costs in connection with the offering of the 8.0% Senior Notes. These costs are included in other assets in the consolidated balance sheet and are being amortized over the term of the notes.

8.75% Senior Notes Due 2020. In December 2009, the Company completed the sale of $450.0 million of unsecured 8.75% Senior Notes due 2020 (the "8.75% Senior Notes") to qualified institutional buyers eligible under Rule 144A of the Securities Act. These notes were issued at a discount which will be amortized into interest expense over the term of the notes. Net proceeds from the offering were approximately $433.1 million after the issuance discount and deducting offering expenses. The Company used such proceeds to fund a portion of the purchase of natural gas and oil properties from Forest during December 2009. The notes bear interest at a fixed rate of 8.75% per annum, payable semi-annually, with the principal due on January 15, 2020. The 8.75% Senior Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices. The notes are jointly and severally, unconditionally guaranteed on an unsecured basis by all of the Company's wholly owned subsidiaries, except certain minor subsidiaries.

In conjunction with the issuance of the 8.75% Senior Notes, the Company entered into a Registration Rights Agreement requiring the Company to register these notes by December 16, 2010. The Company is required to pay additional interest if it fails to fulfill its obligations under the agreement within the specified time periods.

Debt issuance costs of $9.5 million incurred in connection with the offering of the 8.75% Senior Notes are included in other assets in the consolidated balance sheet and are being amortized over the term of the notes.

The indentures governing all of the senior notes contain financial covenants similar to those of the senior credit facility and include limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers. As of and for the year ended December 31, 2009, the Company was in compliance with all of the covenants contained in the indentures governing the senior notes.

Maturities of Long-Term Debt. Aggregate maturities of long-term debt, excluding discounts, during the next five years are as follows (in thousands):

Years ending December 31:	
2010	$ 12,003
2011	7,295
2012	1,051
2013	1,121
2014	1,191
Thereafter	2,578,166
Total debt	$2,600,827

13. Other Long-Term Obligations

Pursuant to a settlement agreement with Conoco, Inc., entered into in January 2007, the Company agreed to pay approximately $25.0 million plus interest, payable in $5.0 million principal increments. The current portion of the unpaid settlement of $5.0 million was included in accounts payable-trade in the accompanying consolidated balance sheets at December 31, 2009 and December 31, 2008. The non-current unpaid settlement amounts of $5.0 million and $10.0 million have been included in other long-term obligations in the accompanying consolidated balance sheets at December 31, 2009 and December 31, 2008, respectively.

14. Derivatives

The Company's derivative contracts have not been designated as hedges. The Company records all derivative contracts, which include commodity derivatives and interest rate swaps, at fair value. Changes in derivative contract fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in loss (gain) on derivative contracts for the commodity derivative contracts and in interest expense for the interest rate swaps in the consolidated statements of operations. Commodity derivative contracts are settled on a monthly basis. Settlements on the interest rate swaps occur quarterly. Derivative assets and liabilities arising from the Company's derivative contracts with the same counterparty that provide for net settlement are reported on a net basis in the consolidated balance sheet.

Commodity Derivatives. The Company is exposed to commodity price risk, which impacts the predictability of its cash flows related to the sale of natural gas and oil. This risk is managed by the Company's use of commodity derivative contracts. These derivative contracts allow the Company to limit its exposure to a portion of its projected natural gas and oil sales. None of the Company's derivative contracts may be terminated early as a result of a party having its credit rating downgraded. At December 31, 2009 and December 31, 2008, the Company's commodity derivative contracts consisted of fixed price swaps and basis swaps, which are described below:

Fixed price swaps: The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.

Basis swaps: The Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and pays the counterparty if the settled price differential is less than the stated terms of the contract, which guarantees the Company a price differential for natural gas from a specified delivery point.

Interest Rate Swaps. The Company is exposed to interest rate risk on its long-term fixed and variable interest rate borrowings. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes the Company to (i) changes in market interest rates reflected in the fair value of the debt and (ii) the risk that the Company may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes the Company to short-term changes in market interest rates as the Company's interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily LIBOR and the federal funds rate.

The Company has entered into two interest rate swap agreements to manage the interest rate risk on a portion of its floating rate debt by effectively fixing the variable interest rate on its Senior Floating Rate Notes. See Note 12 for further discussion of the Company's interest rate swaps.

Fair Value of Derivatives. In accordance with ASC Topic 815, the following table presents the fair value of the Company's derivative contracts as of December 31, 2009 and on a gross basis without regard to same-counterparty netting (in thousands):

Type of Contract	Balance Sheet Classification	December 31, 2009	December 31, 2008
Derivative assets			
Natural gas swaps	Derivative contracts-current	$152,986	$188,045
Oil price swaps	Derivative contracts-current	2,849	13,066
Natural gas swaps	Derivative contracts-noncurrent	—	45,537
Oil price swaps	Derivative contracts-noncurrent	5,362	—
Derivative liabilities			
Natural gas swaps	Derivative contracts-current	(45,714)	—
Oil price swaps	Derivative contracts-current	(4,127)	—
Interest rate swaps	Derivative contracts-current	(7,080)	(5,106)
Natural gas swaps	Derivative contracts-noncurrent	(62,941)	(3,639)
Oil price swaps	Derivative contracts-noncurrent	(2,262)	—
Interest rate swaps	Derivative contracts-noncurrent	(1,219)	—
Total net derivative contracts		$ 37,854	$237,903

A counterparty to one of the Company's derivative contracts, Lehman Brothers, declared bankruptcy on October 3, 2008. Due to Lehman Brothers' bankruptcy, the declaration of bankruptcy by its parent, Lehman Brothers Holdings Inc., on September 15, 2008, and the asset position of the contract, the Company did not assign any value to this derivative contract from September 30, 2008 until September 30, 2009. During August 2009, the Company entered into an agreement with Lehman Brothers to settle all unsettled positions under this derivative contract through September 30, 2009. As of October 1, 2009, Lehman Brothers assigned this contract to a third-party to serve as the counterparty for the remaining three months of the contract.

The following table summarizes the effect of the Company's derivative contracts on the consolidated statements of operations for the years ended December 31, 2009, 2008 and 2007 (in thousands):

Type of Contract	Location of (Gain) Loss Recognized in Income	Amount of (Gain) Loss Recognized in Income		
		2009	2008	2007
Interest rate swap	Interest expense	$ 5,783	$ 7,441	$ —
Natural gas and oil swaps	Gain on derivative contracts	(147,527)	(211,439)	(60,732)
Total		$(141,744)	$(203,998)	$(60,732)

The following table summarizes the cash settlements and valuation gains and losses on commodity derivative contracts for the years ended December 31, 2009, 2008 and 2007 (in thousands):

	Year Ended December 31,		
	2009	2008	2007
Realized (gain) loss	$(348,022)	$ 12,981	$(34,494)
Unrealized loss (gain)	200,495	(224,420)	(26,238)
Gain on commodity derivative contracts	$(147,527)	$(211,439)	$(60,732)

Net losses of $5.8 million ($0.4 million unrealized gain and $6.2 million realized loss) and net losses of $7.4 million ($8.7 million unrealized loss and $1.3 million realized gain) related to the interest rate swaps discussed above were included in interest expense in the accompanying consolidated statement of operations for the year ended December 31, 2009 and December 31, 2008, respectively.

At December 31, 2009, the Company's open natural gas and oil commodity derivative contracts consisted of the following:

Natural Gas

Period and Type of Contract	Notional (MMcf)(1)	Weighted Avg. Fixed Price
January 2010 — March 2010		
Price swap contracts	20,475	$ 7.95
Basis swap contracts	20,250	$(0.74)
April 2010 — June 2010		
Price swap contracts	19,793	$ 7.32
Basis swap contracts	20,475	$(0.74)
July 2010 — September 2010		
Price swap contracts	20,010	$ 7.55
Basis swap contracts	20,700	$(0.74)
October 2010 — December 2010		
Price swap contracts	20,010	$ 7.97
Basis swap contracts	20,700	$(0.74)
January 2011 — March 2011		
Basis swap contracts	25,650	$(0.47)
April 2011 — June 2011		
Basis swap contracts	25,935	$(0.47)
July 2011 — September 2011		
Basis swap contracts	26,220	$(0.47)
October 2011 — December 2011		
Basis swap contracts	26,220	$(0.47)
January 2012 — March 2012		
Basis swap contracts	28,210	$(0.55)
April 2012 — June 2012		
Basis swap contracts	28,210	$(0.55)
July 2012 — September 2012		
Basis swap contracts	28,520	$(0.55)
October 2012 — December 2012		
Basis swap contracts	28,520	$(0.55)
January 2013 — March 2013		
Basis swap contracts	3,600	$(0.46)
April 2013 — June 2013		
Basis swap contracts	3,640	$(0.46)
July 2013 — September 2013		
Basis swap contracts	3,680	$(0.46)
October 2013 — December 2013		
Basis swap contracts	3,680	$(0.46)

(1) Assumes ratio of 1:1 for Mcf to MMBtu.

Oil

Period and Type of Contract	Notional (in MBbls)	Weighted Avg. Fixed Price
January 2010 — March 2010		
Price swap contracts	990	$81.95
April 2010 — June 2010		
Price swap contracts	1,092	$82.05
July 2010 — September 2010		
Price swap contracts	1,104	$82.05
October 2010 — December 2010		
Price swap contracts	1,104	$82.05
January 2011 — March 2011		
Price swap contracts	1,170	$86.52
April 2011 — June 2011		
Price swap contracts	1,183	$86.52
July 2011 — September 2011		
Price swap contracts	1,196	$86.52
October 2011 — December 2011		
Price swap contracts	1,196	$86.52
January 2012 — March 2012		
Price swap contracts	1,092	$88.26
April 2012 — June 2012		
Price swap contracts	1,092	$88.26
July 2012 — September 2012		
Price swap contracts	1,104	$88.26
October 2012 — December 2012		
Price swap contracts	1,104	$88.26

15. Retirement and Deferred Compensation Plans

Retirement Plan. The Company maintains a 401(k) retirement plan for its employees. Under the plan, eligible employees may elect to defer a portion of their earnings up to the maximum allowed by regulations promulgated by the Internal Revenue Service. The 2009 annual 401(k) deferral limit for employees under age 50 was $16,500. Employees turning age 50 or over in 2009 could defer up to $22,000 in 2009. The Company makes matching contributions to the plan equal to 100% on the first 15% of employee deferred wages. All matching contributions are made with Company stock. In 2008 and 2007, the Company satisfied its matching obligations related to employee contributions from the respective previous year through transfers of treasury stock. See Note 20. For 2009 and 2008, the Company satisfied its matching obligations related to employee contributions with cash purchases of Company stock. For 2009, 2008 and 2007, retirement plan expense was approximately $7.4 million, $7.8 million and $4.9 million, respectively.

Deferred Compensation Plan. Effective February 1, 2007 the Company established a non-qualified deferred compensation plan that allows eligible highly compensated employees to elect to defer income in excess of the IRA annual limitations on qualified 401(k) retirement plans. The Company makes matching contributions on non-qualified contributions up to a maximum of 15% of employee gross earnings. For 2009 and 2008, employer contributions were approximately $2.5 million and $1.6 million, respectively. There were no contributions made in 2007.

Any assets placed in trust by the Company to fund future obligations of the Company's non-qualified deferred compensation plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their deferred compensation in the plan.

16. Income Taxes

Deferred income taxes are provided to reflect the future tax consequences of temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets are reduced by a valuation allowance as necessary when a determination is made that it is more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence. As of December 31, 2008, the Company determined it was appropriate to record a full valuation allowance against its net deferred tax asset. For the year ended December 31, 2009, the Company recorded a $641.3 million increase to the previously established valuation allowance. The increase is primarily a result of not recording a tax benefit for the current period net loss attributable to the Company before income taxes of $1,784.3 million.

Significant components of the Company's deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2009	2008
Deferred tax liabilities:		
Derivative contracts	$ 13,627	$ 85,645
Investment in partnerships	3,770	—
Total deferred tax liabilities	17,397	85,645
Deferred tax assets:		
Property, plant and equipment	873,096	555,660
Allowance for doubtful accounts	787	1,414
Net operating loss carryforwards	220,195	2,064
Investment in and notes receivable from partnerships	—	1,880
Compensation and benefits	9,823	6,911
Alternative minimum tax credits and other carryforwards	3,070	2,524
Asset retirement obligation liability	39,681	4,287
Other	2,570	1,422
Total deferred tax assets	1,149,222	576,162
Valuation allowance	(1,131,825)	(490,517)
Net deferred tax liability	$ —	$ —

The (benefits) provisions for income taxes consisted of the following components for the years ended December 31 (in thousands):

	2009	2008	2007
Current:			
Federal	$(4,413)	$ 4,537	$ —
State	(4,303)	4,665	601
	(8,716)	9,202	601
Deferred:			
Federal	—	(46,180)	28,121
State	—	(1,350)	802
	—	(47,530)	28,923
Total (benefit) provision for income taxes	$(8,716)	$(38,328)	$29,524

A reconciliation of the (benefits) provisions for income taxes at the statutory federal tax rate to the Company's actual (benefit) provision for income taxes is as follows for the years ended December 31 (in thousands):

	2009	2008	2007
Computed at federal statutory rate	$(624,507)	$(517,863)	$27,911
State taxes, net of federal benefit	(14,265)	(12,153)	912
Non-deductible expenses	1,905	967	312
Stock-based compensation	5,941	—	—
Other	(19,098)	204	389
Change in valuation allowance	641,308	490,517	—
Total (benefit) provision for income taxes	$ (8,716)	$ (38,328)	$29,524

As of December 31, 2009, the Company has approximately $1.3 million of alternative minimum tax credits available that do not expire. In addition, the Company has approximately $639.3 million of federal net operating loss carryovers that expire during the years 2023 through 2029. Excess tax benefits of $11.5 million associated with the vesting of restricted stock awards are included in the federal net operating loss carryovers, but will not be recognized as a tax benefit recorded to additional paid-in capital until realized.

Internal Revenue Code ("IRC") Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. The Company experienced an ownership change within the meaning of IRC Section 382 on December 31, 2008. As of December 31, 2009, $305.0 million of federal net operating loss carryforwards are subject to the IRC Section 382 limitation which could result in a material amount of these carryforwards expiring unused. The limitation does not result in a current federal tax liability for the period ending December 31, 2009.

No reserves for uncertain income tax positions have been recorded pursuant to the guidance for uncertainty in income taxes under ASC Topic 740, Income Taxes. Tax years 1999 to present remain open for the majority of taxing authorities due to net operating loss carryforwards from those years. The Company's accounting policy is to recognize interest and penalties, if any, related to unrecognized tax benefits as income tax expense. The Company does not have an accrued liability for interest and penalties at December 31, 2009.

17. Earnings (Loss) Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average shares outstanding during the period, but also include the dilutive effect of awards of restricted stock and outstanding convertible preferred stock. The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted earnings per share, for the years ended December 31 (in thousands):

	2009	2008	2007
Weighted average basic common shares outstanding	175,005	155,619	108,828
Effect of dilutive securities:			
Restricted stock	—	—	1,213
Convertible preferred stock	—	—	—
Weighted average diluted common and potential common shares outstanding	175,005	155,619	110,041

For the years ended December 31, 2009 and 2008, restricted stock awards covering approximately 2.8 million and 1.5 million shares, respectively, were excluded from the computation of net loss per share because their effect would have been antidilutive.

In computing diluted earnings per share, the Company evaluated the if-converted method with respect to its outstanding 8.5% convertible perpetual preferred stock and 6.0% convertible perpetual preferred stock (see Note 20) for the year ended December 31, 2009 and with respect to its then outstanding redeemable convertible preferred stock for the years ended December 31, 2008 and 2007. Under this method, the Company assumes the conversion of the preferred stock to common stock and determines if this is more dilutive than including the preferred stock dividends (paid and unpaid) in the computation of income available to common stockholders. The Company determined the if-converted method was not more dilutive and included preferred stock dividends in the determination of income available to common stockholders for the years ended December 31, 2009, 2008 and 2007.

18. Commitments and Contingencies

Operating Leases. The Company has obligations under noncancelable operating leases, primarily for the use of office space. Total rental expense under operating leases for the years ended December 31, 2009, 2008 and 2007 was approximately $3.2 million, $2.4 million and $2.3 million, respectively.

Future minimum lease payments under noncancelable operating leases (with initial lease terms in excess of one year) as of December 31, 2009 were as follows (in thousands):

Years ending December 31:	
2010	$2,043
2011	827
2012	292
2013	158
2014	48
	$3,368

Rig Commitments. The Company has contracts with third-party drilling rig operators for the use of their rigs at specified day rates. These commitments are not recorded in the consolidated balance sheets. Minimum future commitments as of December 31, 2009 were $1.2 million for 2010.

Purchase Commitment. The Company has a contract to purchase pipe for use in its drilling and production activities. This commitment is not recorded in the consolidated balance sheet. Minimum future commitments as of December 31, 2009 were $21.6 million for 2010.

Firm Transportation. The Company has subscribed firm gas transportation service under two Transportation Service Agreements ("TSA"). The TSA terms run through 2012 on the Oasis Pipeline and through 2018 on the Midcontinent Express Pipeline. These commitments are not recorded in the consolidated balance sheets. Under the terms of the TSAs, the Company is obligated to pay a demand charge and in exchange, obtains the right to flow natural gas production through these pipelines to more competitive marketing areas. The amounts of the required payments for firm transportation as of December 31, 2009 were as follows (in thousands):

Years ending December 31:	
2010	$ 35,307
2011	30,391
2012	30,612
2013	24,725
2014	16,483
Thereafter	65,979
	$203,497

Gas Gathering Agreement. In conjunction with the sale of the gathering and compression assets located in the Piñon Field of the WTO, the Company entered into a gas gathering agreement. Under the gas gathering agreement, the Company has dedicated its Piñon Field acreage for priority gathering services over a period of 20 years and the Company will pay a fee that was negotiated at arms' length for such services. Pursuant to the gas gathering agreement, the base fee can be reduced if certain criteria are met. The table below presents the base fee contractual obligations under this agreement as of December 31, 2009 (in thousands).

Years ending December 31:	
2010	$ 22,226
2011	33,780
2012	42,814
2013	42,634
2014	42,360
Thereafter	305,390
	$489,204

Litigation. The Company is a defendant in lawsuits from time to time in the normal course of business. In management's opinion, the Company is not currently involved in any legal proceedings which, individually or in the aggregate, could have a material effect on the financial condition, operations or cash flows of the Company.

19. Redeemable Convertible Preferred Stock

In November 2006, the Company sold 2,136,667 shares of redeemable convertible preferred stock to finance a portion of the NEG acquisition and received net proceeds of approximately $439.5 million after deducting offering expenses of approximately $9.3 million. Each holder of redeemable convertible preferred stock was entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value, or $210 per share, of their redeemable convertible preferred stock. Each share of redeemable convertible preferred stock was initially convertible into 10.0 shares, and ultimately convertible into 10.2 shares, of common stock at the option of the holder, subject to certain anti-dilution adjustments. A summary of dividends declared and paid on the redeemable convertible preferred stock is as follows (in thousands, except per share data):

Declared	Dividend Period	Dividends per Share	Total	Payment Date
January 31, 2007	November 21, 2006 — February 1, 2007	$3.21	$6,859	February 15, 2007
May 8, 2007	February 2, 2007 — May 1, 2007	3.97	8,550	May 15, 2007
June 8, 2007	May 2, 2007 — August 1, 2007	4.10	8,956	August 15, 2007
September 24, 2007	August 2, 2007 — November 1, 2007	4.10	8,956	November 15, 2007
December 16, 2007	November 2, 2007 — February 1, 2008	4.10	8,956	February 15, 2008
March 7, 2008	February 2, 2008 — May 1, 2008	4.01	8,095	(1)
May 7, 2008	May 2, 2008 — May 7, 2008	4.01	501	May 7, 2008

(1) Includes $0.6 million of prorated dividends paid to holders of redeemable convertible preferred shares at the time their shares converted to common stock in March 2008. The remaining dividends of $7.5 million were paid during May 2008.

On March 30, 2007, certain holders of the Company's common units (consisting of shares of common stock and a warrant to purchase redeemable convertible preferred stock upon the surrender of common stock) exercised warrants to purchase redeemable convertible preferred stock. The holders converted 526,316 shares of common stock into 47,619 shares of redeemable convertible preferred stock.

During March 2008, holders of 339,823 shares of the Company's redeemable convertible preferred stock elected to convert those shares into 3,465,593 shares of the Company's common stock. Additionally, during May 2008, the Company converted the remaining outstanding 1,844,464 shares of its redeemable convertible preferred stock into 18,810,260 shares of its common stock as permitted under the terms of the redeemable convertible preferred stock. These conversions resulted in increases to additional paid-in capital totaling $452.2 million, which represents the difference between the par value of the common stock issued and the carrying value of the redeemable convertible shares converted. The Company also recorded charges to retained earnings totaling $7.2 million in accelerated accretion expense related to the converted redeemable convertible preferred shares. Prorated dividends totaling $0.5 million for the period from May 2, 2008 to the date of conversion (May 7, 2008) were paid to the holders of the converted shares on May 7, 2008. On and after the conversion date, dividends ceased to accrue and the rights of common unit holders to exercise outstanding warrants to purchase redeemable convertible preferred shares terminated.

Approximately $8.6 million in paid and unpaid dividends on the redeemable convertible preferred stock has been included in the Company's earnings per share calculations for the year ended December 31, 2008, as presented in the accompanying consolidated statement of operations. No shares of redeemable convertible preferred stock were outstanding during the year ended December 31, 2009.

20. Equity

Preferred Stock

The following table presents information regarding the Company's preferred stock (in thousands):

	December 31, 2009	December 31, 2008
Shares authorized	50,000	50,000
Shares outstanding at end of period:		
8.5% Convertible perpetual preferred stock	2,650	—
6.0% Convertible perpetual preferred stock	2,000	—

The Company is authorized to issue 50,000,000 shares of preferred stock, $0.001 par value, of which 4,650,000 shares are designated as convertible perpetual preferred stock at December 31, 2009. There were no shares of preferred stock outstanding as of December 31, 2008. See Note 19 for discussion of conversion of redeemable preferred stock during 2008.

8.5% Convertible perpetual preferred stock. In January 2009, the Company completed a private placement of 2,650,000 shares of 8.5% convertible perpetual preferred stock to qualified institutional investors eligible under Rule 144A under the Securities Act. The offering included 400,000 shares of convertible perpetual preferred stock issued upon the full exercise of the initial purchaser's option to cover over-allotments. Net proceeds from the offering were approximately $243.3 million after deducting offering expenses of approximately $8.6 million. The Company used the net proceeds from the offering to repay outstanding borrowings under the senior credit facility and for general corporate purposes.

Each share of 8.5% convertible perpetual preferred stock has a liquidation preference of $100 and is convertible at the holder's option at any time initially into approximately 12.4805 shares of the Company's common stock based on an initial conversion price of $8.01, subject to adjustments upon the occurrence of certain events. Each holder of the convertible perpetual preferred stock is entitled to an annual dividend of $8.50 per share to be paid semi-annually in cash, common stock or a combination thereof, at the Company's election, with the first dividend payment due in February 2010. Approximately $8.4 million in unpaid dividends on the 8.5% convertible perpetual preferred stock has been included in the Company's earnings per share calculations for the year ended December 31, 2009 as presented in the accompanying consolidated statements of operations. The 8.5% convertible perpetual preferred stock is not redeemable by the Company at any time. After February 20, 2014, the Company may cause all outstanding shares of the convertible perpetual preferred stock to automatically convert into common stock at the then-prevailing conversion rate if certain conditions are met.

6.0% Convertible perpetual preferred stock. In December 2009, the Company completed a private placement of 2,000,000 shares of 6.0% convertible perpetual preferred stock to an institutional investor in a transaction exempt from registration under Regulation D under the Securities Act. Net proceeds were approximately $199.9 million and were used to fund a portion of the purchase of natural gas and oil properties from Forest during December 2009 and for general corporate purposes.

Each share of the 6.0% convertible perpetual preferred stock has a liquidation preference of $100.00 and is entitled to an annual dividend of $6.00 payable semi-annually in cash, common stock or any combination thereof, at the Company's election, beginning on July 15, 2010. Approximately $0.4 million in unpaid dividends on the 6.0% convertible perpetual preferred stock has been included in the Company's earnings per share calculations for the year ended December 31, 2009 as presented in the accompanying consolidated statements of operations. The 6.0% convertible perpetual preferred stock in not redeemable by the Company at any time. Each share is initially convertible into 9.21 shares of the Company's common stock, at the holder's option, at any time on or after February 1, 2010 based on an initial conversion price of $10.86 and subject to customary adjustments in certain circumstances. Five years after their issuance, all outstanding shares of the convertible preferred stock will be converted automatically into shares of the Company's common stock at the then-prevailing conversion price as long as all dividends accrued at that time have been paid.

Common Stock

The following table presents information regarding the Company's common stock (in thousands):

	December 31, 2009	December 31, 2008
Shares authorized	400,000	400,000
Shares outstanding at end of period	208,715	166,046
Shares held in treasury	1,866	1,326

In March 2007, the Company sold approximately 17.8 million shares of common stock for net proceeds of $318.7 million after deducting offering expenses of approximately $1.4 million. The stock was sold in private sales to various investors including the Company's Chairman and Chief Executive Officer, who invested $61.4 million in exchange for approximately 3.4 million shares of common stock.

On November 9, 2007, the Company completed the initial public offering of its common stock. The Company sold 32,379,500 shares of its common stock, including 4,710,000 shares sold directly to an entity controlled by the Company's Chairman and Chief Executive Officer, at a price of $26.00 per share. After deducting underwriting discounts of approximately $44.0 million and offering expenses of approximately $3.1 million, the Company received net proceeds of approximately $794.7 million. The Company used the net proceeds from the offering as follows (in millions):

Repayment of outstanding balance and accrued interest on senior credit facility	$515.9
Repayment of note payable and accrued interest incurred in connection with recent acquisition	49.1
Excess cash to fund future capital expenditures	229.7
Total	$794.7

During March 2008, the Company issued 3,465,593 shares of common stock upon the conversion of 339,823 shares of its redeemable convertible preferred stock. In May 2008, the Company converted the remaining 1,844,464 outstanding shares of its redeemable convertible preferred stock into 18,810,260 shares of its common stock as permitted under the terms of the redeemable convertible preferred stock. See additional discussion at Note 19.

In April 2009, the Company completed a registered underwritten offering of 14,480,000 shares of its common stock, including 2,280,000 shares of common stock acquired by the underwriters from the Company to cover over-allotments. Net proceeds to the Company from the offering were approximately $107.6 million, after deducting offering expenses of approximately $2.4 million, and were used to repay a portion of the amount outstanding under the senior credit facility and for general corporate purposes.

In December 2009, the Company completed a registered underwritten public offering of 25,600,000 shares of its common stock, including 3,600,000 shares of common stock acquired by the underwriters from the Company to cover over-allotments. Net proceeds from the offering were approximately $217.2 million after deducting offering expenses of approximately $9.4 million. The net proceeds were used to fund the purchase of natural gas and oil properties from Forest and for general corporate purposes.

Treasury Stock

The Company makes required tax payments on behalf of employees when their restricted stock awards vest and then withholds a number of vested shares of common stock having a value on the date of vesting equal to the tax obligation. As a result of such transactions, the Company withheld 167,009 shares having a total value of $1.5 million, 80,724 shares having a total value of $3.6 million, and 44,649 shares having a total value of $0.8 million during the years ended December 31, 2009, 2008 and 2007, respectively. These shares were accounted for as treasury stock.

In June 2007, the Company purchased 39,844 shares of its common stock into treasury through an open market repurchase transaction in order to fund a portion of its 401(k) matching obligation as described below. Cash consideration for these shares of approximately $0.8 million was paid in July 2007.

In June 2007, the Company transferred 72,044 shares of its treasury stock to an account established for the benefit of the Company's 401(k) Plan. The transfer was made in order to satisfy the Company's $1.3 million accrued payable to match employee contributions made to the plan during 2006. Historical cost of the shares transferred totaled approximately $0.9 million, resulting in an increase to the Company's additional paid-in capital of approximately $0.4 million.

In February 2008, the Company transferred 184,484 shares of its treasury stock into an account established for the benefit of the Company's 401(k) Plan. The transfer was made in order to satisfy the Company's $5.0 million accrued payable to match employee contributions made to the plan during 2007. The historical cost of the shares transferred totaled approximately $2.4 million and resulted in an increase to the Company's additional paid-in capital of approximately $2.6 million.

Equity Compensation

The Company awards restricted common stock under incentive compensation plans that vest over specified periods of time, subject to certain conditions. Awards issued prior to 2006 had vesting periods of one, four or seven years. All awards issued during and after 2006 have four year vesting periods. Shares of restricted common stock are subject to restriction on transfer. Unvested restricted stock awards are included in the Company's outstanding shares of common stock.

Equity compensation provided to employees directly involved in natural gas and oil exploration and development activities is capitalized to the Company's natural gas and oil properties. Equity compensation not capitalized is reflected in general and administrative expenses, production expenses, midstream and marketing expenses and drilling and services expenses in the consolidated statements of operations. For the year ended December 31, 2009, the Company recognized equity compensation expense of $22.8 million, net of $4.3 million capitalized, related to restricted common stock. For the years ended December 31, 2008 and 2007, the Company recognized equity compensation expense of $18.8 million and $7.2 million, respectively, related to restricted common stock. There was no equity compensation capitalized in 2008 or 2007.

Effective June 5, 2009, the Company adopted the SandRidge Energy, Inc. 2009 Incentive Plan (the "2009 Incentive Plan"). Under the terms of the 2009 Incentive Plan, the Company may grant stock options, stock appreciation rights, shares of restricted stock, restricted stock units and other forms of awards based on the value (or increase in the value) of shares of the common stock of the Company for up to 12,000,000 shares of common stock. The 2009 Incentive Plan also permits cash incentive awards. Consistent with its other incentive plans, the Company intends for shares of restricted stock to be the primary form of awards granted under the 2009 Incentive Plan.

Restricted stock activity for the year ended December 31, 2009 was as follows (shares in thousands):

	Number of Shares	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2008	2,993	$30.71
Granted	3,531	$ 8.34
Vested	(800)	$29.43
Canceled	(402)	$20.97
Unvested restricted shares outstanding at December 31, 2009	5,322	$16.80

As of December 31, 2009, there was approximately $69.4 million of unrecognized compensation cost related to unvested restricted stock awards, which is expected to be recognized over a weighted average period of 2.9 years.

Noncontrolling Interest

Noncontrolling interests in certain of the Company's subsidiaries represents ownership interests in the consolidated entity and are included as a component of equity in the consolidated balance sheets and consolidated statement of changes in equity as required by the Consolidation Topic of the ASC.

21. Related Party Transactions

The Company enters into transactions in the ordinary course of business with certain of its stockholders and other related parties. These transactions primarily consist of purchases of gas treating services and drilling equipment and sales of oil field services and natural gas. Following is a summary of all significant transactions with such related parties for years ended December 31 (in thousands):

	2009	2008	2007
Sales to and reimbursements from related parties	$ 7,304	$90,170	$118,631
Purchases of services from related parties	$21,745	$59,951	$ 77,555

In 2007, the Company purchased leasehold acreage from a partnership controlled by a director. The purchase price was approximately $8.3 million, which was paid in cash. Also in 2007, the Company purchased certain producing well interests from a director. The purchase price was approximately $3.5 million, which was paid in cash.

In 2008, the Company purchased certain working interests and related reserves in Company wells owned by its Chairman and Chief Executive Officer and certain of his affiliates. The purchase price was $67.3 million. See Note 2.

Oklahoma City Thunder Agreements. The Company's Chairman and Chief Executive Officer owns a minority interest in a limited liability company which owns and operates the Oklahoma City Thunder, a National

Basketball Association team playing in Oklahoma City, where the Company is headquartered. The Company is party to a five-year sponsorship agreement whereby it pays approximately $3.3 million per year for advertising and promotional activities related to the Oklahoma City Thunder. Additionally, the Company entered into an agreement to license a suite at the arena where the Oklahoma City Thunder plays its home games. Under this four-year agreement, the Company will pay an annual license fee of $0.2 million.

Larclay, L.P. As previously discussed in Note 8, Lariat owned a 50% interest in Larclay until April 15, 2009. At that time, Lariat assigned its interest in Larclay to CWEI. The following table summarizes the Company's transactions with Larclay for the period from January 1, 2009 through April 15, 2009 and for the years ended December 31, 2008 and 2007 (in thousands):

	2009	2008	2007
Sales to and reimbursements from Larclay	$3,125	$42,757	$53,256
Purchases of services from Larclay	$1,762	$34,747	$33,297

22. Subsequent Events

Events occurring after December 31, 2009 were evaluated to ensure that any subsequent events that met the criteria for recognition and/or disclosure in this report have been included.

23. Business Segment Information

The Company has three business segments: exploration and production, drilling and oil field services and midstream gas services. These segments represent the Company's three main business units, each offering different products and services. The exploration and production segment is engaged in the acquisition, development and production of natural gas and oil properties. The drilling and oil field services segment is engaged in the land contract drilling of natural gas and oil wells. The midstream gas services segment is engaged in the purchasing, gathering, processing, treating and selling of natural gas. The All Other column in the tables below includes items not related to the Company's reportable segments, including the Company's CO_2 gathering and sales operations and corporate operations.

Management evaluates the performance of the Company's business segments based on operating income, which is defined as segment operating revenues less operating expenses and depreciation, depletion and amortization. Summarized financial information concerning the Company's segments is shown in the following table (in thousands):

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2009					
Revenues	$ 457,397	$ 225,227	$ 299,580	$ 30,654	$ 1,012,858
Inter-segment revenue	(261)	(201,641)	(215,667)	(4,245)	(421,814)
Total revenues	$ 457,136	$ 23,586	$ 83,913	$ 26,409	$ 591,044
Operating loss(1)	$(1,488,078)	$ (15,166)	$ (36,989)	$ (64,791)	$(1,605,024)
Interest expense, net	(180,856)	(2,074)	(1,246)	(1,140)	(185,316)
Other income, net	4,673	—	3,365	254	8,292
Loss before income taxes	$(1,664,261)	$ (17,240)	$ (34,870)	$ (65,677)	$(1,782,048)
Capital expenditures(2)	$ 555,809	$ 4,090	$ 52,425	$ 32,818	$ 645,142
Depreciation, depletion and amortization	$ 178,783	$ 28,221	$ 5,496	$ 14,392	$ 226,892
At December 31, 2009					
Total assets	$ 2,313,582	$ 229,507	$ 110,757	$126,471	$ 2,780,317
Year Ended December 31, 2008					
Revenues	$ 912,716	$ 434,963	$ 688,071	$ 22,791	$ 2,058,541
Inter-segment revenue	(220)	(387,972)	(483,933)	(4,602)	(876,727)
Total revenues	$ 912,496	$ 46,991	$ 204,138	$ 18,189	$ 1,181,814
Operating (loss) income(1)	$(1,263,249)	$ (5,393)	$ 2,087	$ (71,592)	$(1,338,147)
Interest expense, net	(139,494)	(2,766)	—	(1,198)	(143,458)
Other income, net	1,171	1,015	398	268	2,852
(Loss) income before income taxes	$(1,401,572)	$ (7,144)	$ 2,485	$ (72,522)	$(1,478,753)
Capital expenditures(2)	$ 1,909,078	$ 52,869	$ 160,460	$ 55,440	$ 2,177,847
Depreciation, depletion and amortization	$ 293,625	$ 42,077	$ 15,241	$ 10,422	$ 361,365
At December 31, 2008					
Total assets	$ 2,986,070	$ 275,164	$ 284,281	$109,543	$ 3,655,058
Year Ended December 31, 2007					
Revenues	$ 479,321	$ 261,818	$ 285,065	$ 29,286	$ 1,055,490
Inter-segment revenue	(574)	(188,616)	(177,487)	(11,361)	(378,038)
Total revenues	$ 478,747	$ 73,202	$ 107,578	$ 17,925	$ 677,452
Operating income (loss)	$ 198,913	$ 10,473	$ 6,783	$ (29,310)	$ 186,859
Interest expense, net	(109,458)	(2,762)	(165)	(106)	(112,491)
Other income, net	713	2,391	1,981	16	5,101
Income (loss) before income taxes	$ 90,168	$ 10,102	$ 8,599	$ (29,400)	$ 79,469
Capital expenditures(2)	$ 1,046,552	$ 123,232	$ 63,828	$ 47,236	$ 1,280,848
Depreciation, depletion and amortization	$ 175,565	$ 37,792	$ 6,641	$ 7,111	$ 227,109
At December 31, 2007					
Total assets	$ 3,143,137	$ 271,563	$ 127,822	$ 88,044	$ 3,630,566

(1) The operating loss for the exploration and production segment for the years ended December 31, 2009 and 2008 includes non-cash full cost ceiling impairments of $1,693.3 million and $1,855.0 million, respectively, on the Company's natural gas and oil properties. The operating loss for the midstream gas services segment for the year ended December 31, 2009 includes a $26.1 million loss on the sale of its gathering and compression assets in the Piñon Field.

(2) On an accrual basis.

Major Customer. During 2009, 2008 and 2007, the Company had sales in excess of 10% of total revenues to a natural gas and oil purchaser ($120.1 million or 20.0% of total revenues, $124.6 million or 10.5% of total revenues, and $76.1 million or 11.2% of total revenues, respectively).

24. Condensed Consolidating Financial Information

The Company provides condensed consolidating financial information for its subsidiaries that are guarantors of its registered debt. The subsidiary guarantors are wholly owned and have, jointly and severally, unconditionally guaranteed on an unsecured basis the Company's 8.625% Senior Notes and Senior Floating Rate Notes. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated in right of payment to any existing or future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; and (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors who are not themselves guarantors. The Company has not presented separate financial and narrative information for each of the subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees.

Effective May 1, 2009, SandRidge Energy, Inc., the parent, contributed all of its rights, title and interest in its natural gas and oil related assets and accompanying liabilities to one of its wholly owned guarantor subsidiaries, leaving it with no natural gas or oil related assets or operations.

The following condensed consolidating financial information represents the financial information of SandRidge Energy, Inc., and its wholly owned subsidiary guarantors, prepared on the equity basis of accounting. The non-guarantor subsidiaries are minor and, therefore, not presented separately. The financial information may not necessarily be indicative of the financial position, results of operations, or cash flows had the subsidiary guarantors operated as independent entities.

Condensed Consolidating Balance Sheets

	December 31, 2009			
	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 339	$ 7,522	$ —	$ 7,861
Accounts receivable, net	642,317	239,719	(776,560)	105,476
Derivative contracts	—	105,994	—	105,994
Other current assets	—	36,633	—	36,633
Total current assets	642,656	389,868	(776,560)	255,964
Property, plant and equipment, net	—	2,433,643	—	2,433,643
Investment in subsidiaries	1,813,887	—	(1,813,887)	—
Other assets	49,103	41,607	—	90,710
Total assets	$2,505,646	$2,865,118	$(2,590,447)	$2,780,317
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 159,693	$ 820,775	$ (776,560)	$ 203,908
Other current liabilities	7,080	14,556	—	21,636
Total current liabilities	166,773	835,331	(776,560)	225,544
Long-term debt	2,543,611	23,324	—	2,566,935
Asset retirement obligation	—	108,584	—	108,584
Other liabilities	1,219	73,940	—	75,159
Total liabilities	2,711,603	1,041,179	(776,560)	2,976,222
(Deficit) equity	(205,957)	1,823,939	(1,813,887)	(195,905)
Total liabilities and equity	$2,505,646	$2,865,118	$(2,590,447)	$2,780,317

	December 31, 2008			
	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets:				
Cash and cash equivalents	$ 18	$ 618	$ —	$ 636
Accounts receivable, net	863,129	66,463	(820,519)	109,073
Derivative contracts	201,111	—	—	201,111
Other current assets	3,194	41,899	—	45,093
Total current assets	1,067,452	108,980	(820,519)	355,913
Property, plant and equipment, net	1,106,623	2,068,936	—	3,175,559
Investment in subsidiaries	1,002,336	—	(1,002,336)	—
Other assets	135,161	39,809	(51,384)	123,586
Total assets	$3,311,572	$2,217,725	$(1,874,239)	$3,655,058
LIABILITIES AND EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 163,068	$1,024,018	$ (820,519)	$ 366,567
Other current liabilities	5,106	30,951	—	36,057
Total current liabilities	168,174	1,054,969	(820,519)	402,624
Long-term debt	2,323,458	86,710	(51,384)	2,358,784
Asset retirement obligation	12,759	71,738	—	84,497
Other liabilities	13,660	1,942	—	15,602
Total liabilities	2,518,051	1,215,359	(871,903)	2,861,507
Equity	793,521	1,002,366	(1,002,336)	793,551
Total liabilities and equity	$3,311,572	$2,217,725	$(1,874,239)	$3,655,058

Condensed Consolidating Statements of Operations

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Year Ended December 31, 2009				
Total revenues	$ 58,273	$ 534,876	$ (2,105)	$ 591,044
Expenses:				
Direct operating expenses	27,737	283,665	(2,105)	309,297
General and administrative	15,645	84,611	—	100,256
Depreciation, depletion, amortization and impairment	627,478	1,306,564	—	1,934,042
(Gain) loss on derivative contracts	(237,351)	89,824	—	(147,527)
Total expenses	433,509	1,764,664	(2,105)	2,196,068
Loss from operations	(375,236)	(1,229,788)	—	(1,605,024)
Equity earnings from subsidiaries	(1,227,164)	—	1,227,164	—
Interest expense, net	(182,009)	(3,307)	—	(185,316)
Other income, net	103	8,189	—	8,292
Loss before income tax benefit	(1,784,306)	(1,224,906)	1,227,164	(1,782,048)
Income tax benefit	(8,716)	—	—	(8,716)
Net loss	(1,775,590)	(1,224,906)	1,227,164	(1,773,332)
Less: net income attributable to noncontrolling interest	—	2,258	—	2,258
Net loss attributable to SandRidge Energy, Inc.	$(1,775,590)	$(1,227,164)	$1,227,164	$(1,775,590)
Year Ended December 31, 2008				
Total revenues	$ 329,109	$ 855,184	$ (2,479)	$ 1,181,814
Expenses:				
Direct operating expenses	72,473	323,172	(2,479)	393,166
General and administrative	40,638	68,734	—	109,372
Depreciation, depletion, amortization and impairment	957,509	1,271,353	—	2,228,862
Gain on derivative contracts	(211,439)	—	—	(211,439)
Total expenses	859,181	1,663,259	(2,479)	2,519,961
Loss from operations	(530,072)	(808,075)	—	(1,338,147)
Equity earnings from subsidiaries	(809,594)	—	809,594	—
Interest expense, net	(140,022)	(3,436)	—	(143,458)
Other income, net	36	2,816	—	2,852
Loss before income tax (benefit) expense	(1,479,652)	(808,695)	809,594	(1,478,753)
Income tax (benefit) expense	(38,372)	44	—	(38,328)
Net loss	(1,441,280)	(808,739)	809,594	(1,440,425)
Less: net income attributable to noncontrolling interest	—	855	—	855
Net loss attributable to SandRidge Energy, Inc.	$(1,441,280)	$ (809,594)	$ 809,594	$(1,441,280)

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Year Ended December 31, 2007				
Total revenues	$ 139,281	$538,171	$ —	$ 677,452
Expenses:				
Direct operating expenses	33,643	228,793	—	262,436
General and administrative	32,446	29,334	—	61,780
Depreciation, depletion and amortization	43,257	183,852	—	227,109
Gain on derivative contracts	(26,183)	(34,549)	—	(60,732)
Total expenses	83,163	407,430	—	490,593
Income from operations	56,118	130,741	—	186,859
Equity earnings from subsidiaries	137,515	—	(137,515)	—
Interest (expense) income, net	(113,838)	1,347	—	(112,491)
Other (expense) income, net	(81)	5,182	—	5,101
Income before income tax expense	79,714	137,270	(137,515)	79,469
Income tax expense	29,493	31	—	29,524
Net income	50,221	137,239	(137,515)	49,945
Less: net loss attributable to noncontrolling interest	—	(276)	—	(276)
Net income attributable to SandRidge Energy, Inc.	$ 50,221	$137,515	$(137,515)	$ 50,221

Condensed Consolidating Statements of Cash Flows

	Parent Company	Guarantor Subsidiaries	Eliminations	Consolidated
		(In thousands)		
Year Ended December 31, 2009				
Net cash (used in) provided by operating activities	$ (717,969)	$ 1,029,528	$ —	$ 311,559
Net cash used in investing activities	(240,992)	(1,006,067)	—	(1,247,059)
Net cash provided by (used in) financing activities	959,282	(16,557)	—	942,725
Net increase in cash and cash equivalents	321	6,904	—	7,225
Cash and cash equivalents at beginning of year	18	618	—	636
Cash and cash equivalents at end of year	$ 339	$ 7,522	$ —	$ 7,861
Year Ended December 31, 2008				
Net cash (used in) provided by operating activities	$ (309,359)	$ 888,548	$ —	$ 579,189
Net cash used in investing activities	(1,042,633)	(866,810)	—	(1,909,443)
Net cash provided by (used in) financing activities	1,289,043	(21,288)	—	1,267,755
Net (decrease) increase in cash and cash equivalents	(62,949)	450	—	(62,499)
Cash and cash equivalents at beginning of year	62,967	168	—	63,135
Cash and cash equivalents at end of year	$ 18	$ 618	$ —	$ 636
Year Ended December 31, 2007				
Net cash (used in) provided by operating activities	$ (301,288)	$ 667,724	$(8,984)	$ 357,452
Net cash used in investing activities	(728,697)	(656,884)	—	(1,385,581)
Net cash provided by (used in) financing activities	1,061,505	(18,173)	8,984	1,052,316
Net increase (decrease) in cash and cash equivalents	31,520	(7,333)	—	24,187
Cash and cash equivalents at beginning of year	31,447	7,501	—	38,948
Cash and cash equivalents at end of year	$ 62,967	$ 168	$ —	$ 63,135

25. Supplemental Information on Oil and Gas Producing Activities

The Supplementary Information on Oil and Gas Producing Activities is presented as required by ASC Topic 932, Extractive Activities — Oil and Gas. The supplemental information includes capitalized costs related to oil and gas producing activities; costs incurred in oil and gas property acquisition, exploration and development; and the results of operations for oil and gas producing activities. Supplemental information is also provided for oil and gas production and average sales prices; the estimated quantities of proved oil and gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

Capitalized Costs Related to Oil and Gas Producing Activities

The Company's capitalized costs consisted of the following (in thousands):

	December 31,		
	2009	2008	2007
Natural gas and oil properties:			
Proved	$ 5,913,408	$ 4,676,072	$2,848,531
Unproved	281,811	215,698	259,610
Total natural gas and oil properties	6,195,219	4,891,770	3,108,141
Less accumulated depreciation, depletion and impairment	(4,223,437)	(2,369,840)	(230,974)
Net natural gas and oil properties capitalized costs	$ 1,971,782	$ 2,521,930	$2,877,167

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development

Costs incurred in oil and gas property acquisition, exploration and development activities which have been capitalized are summarized as follows (in thousands):

	2009	2008	2007
Acquisitions of properties:			
Proved	$ 749,070	$ 366,275	$ 303,282
Unproved	67,731	16,982	—
Exploration(1)	126,345	391,672	361,973
Development	407,409	1,132,078	485,348
Total cost incurred	$1,350,555	$1,907,007	$1,150,603

(1) Includes seismic costs of $6.8 million, $68.8 million and $38.6 million for 2009, 2008 and 2007, respectively. 2009 and 2008 amounts also include pipe inventory costs of $77.7 million and $47.2 million, respectively.

Results of Operations for Oil and Gas Producing Activities (Unaudited)

The Company's results of operations from oil and gas producing activities for each of the years 2007, 2008 and 2009 are shown in the following table (in thousands):

For the Year Ended December 31, 2007	
Revenues	$ 477,612
Expenses:	
Production costs	125,749
Depreciation, depletion and amortization expenses	169,392
Total expenses	295,141
Income before income taxes	182,471
Provision for income taxes	65,690
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$ 116,781
For the Year Ended December 31, 2008	
Revenues	$ 908,689
Expenses:	
Production costs	189,598
Depreciation, depletion, amortization and impairment expenses	2,140,685
Total expenses	2,330,283
Loss before income taxes	(1,421,594)
Benefit of income taxes	(36,819)
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$(1,384,775)
For the Year Ended December 31, 2009	
Revenues	$ 454,705
Expenses:	
Production costs	173,295
Depreciation, depletion, amortization and impairment expenses	1,869,314
Total expenses	2,042,609
Loss before income taxes	(1,587,904)
Benefit of income taxes	(7,940)
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$(1,579,964)

Oil and Gas Reserve Quantities (Unaudited)

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time of which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

The table below represents the Company's estimate of proved natural gas and oil reserves attributable to the Company's net interest in oil and gas properties, all of which are located in the continental United States, based upon the evaluation by the Company and its independent petroleum engineers of pertinent geoscience and engineering data in accordance with the Securities and Exchange Commission's regulations. Estimates of substantially all of the Company's proved reserves have been prepared by independent reservoir engineers and geoscience professionals and are reviewed by members of the Company's senior management with professional training in petroleum engineering to ensure that the Company consistently applies rigorous professional standards and the reserve definitions prescribed by the SEC.

Netherland, Sewell & Associates, Inc., DeGolyer and MacNaughton and Lee Keeling and Associates, Inc., independent oil and gas consultants, prepared the estimates of proved reserves of natural gas and oil attributable to substantially all of the Company's net interest in natural gas and oil properties as of the end of one or more of 2009, 2008 and 2007. Netherland, Sewell & Associates, Inc., DeGolyer and MacNaughton and Lee Keeling and Associates, Inc., are independent petroleum engineers, geologists, geophysicists and petrophysicists and do not own an interest in the Company or its properties and are not employed on a contingent basis. Netherland, Sewell & Associates, Inc. and Lee Keeling and Associates, Inc., prepared the estimates of proved reserves for a majority of the Company's properties other than those held by SandRidge Tertiary, LLC (formerly PetroSource Production Co), which constitute approximately 85.4% of the Company's total proved reserves as of December 31, 2009. DeGolyer and MacNaughton prepared the estimates of proved reserves for SandRidge Tertiary, LLC, which constitute approximately 9.6% of our total proved reserves as of December 31, 2009. The small remaining portion of estimates of proved reserves were based on Company estimates.

The Company believes the geoscience and engineering data examined provides reasonable assurance that the proved reserves are economically producible in future years from known reservoirs, and under existing economic conditions, operating methods and governmental regulations. Estimates of proved reserves are subject to change, either positively or negatively, as additional information is available and contractual and economic conditions change.

During 2008 and 2007, the Company recognized additional reserves attributable to extensions and discoveries as a result of successful drilling in the Piñon Field. Drilling expenditures of $129.8 million and $97.1 million resulted in the addition of 57.8 Bcfe and 44.7 Bcfe, respectively, of net proved developed reserves by extending the field boundaries as well as proving the producing capabilities of formations not previously captured as proved reserves. The remaining 136.5 Bcfe and 55.1 Bcfe of net proved reserve extensions in the Piñon Field for 2008 and 2007, respectively, are proved undeveloped reserves associated with direct offsets to the drilling program extending the boundaries of the Piñon Field and zone identification. Changes in reserves associated with the development drilling have been accounted for in revisions of previous reserve estimates.

During 2009, the Company recognized downward revisions of 1,123.8 Bcf in its natural gas reserve quantities as lower natural gas prices used in the estimation of reserves as of December 31, 2009 caused (1) a significant number of proved undeveloped reserve locations to generate no discounted future net cash flows resulting in the elimination of associated reserve quantities and (2) a shortening of the productive lives of certain proved properties that became uneconomic earlier in their lives with the use of lower gas prices compared to prices used in the estimation of reserves in the previous periods. The natural gas price used in the estimation as of December 31, 2009, which is a 12-month average price in accordance with SEC rules, was $3.87 per Mcf compared to the index price at December 31, 2008 of $5.71 per Mcf used in the estimation of year end 2008 reserves. The remaining 121.1 Bcf of negative revisions are performance related.

The summary below presents changes in the Company's estimated reserves for 2007, 2008 and 2009.

	Oil (MBbls)	Nat. Gas (MMcf)(1)
Proved developed and undeveloped reserves:		
As of December 31, 2006	25,175	850,708
Revisions of previous estimates	5,492	318,639
Acquisitions of new reserves	53	75,139
Extensions and discoveries	7,849	104,501
Production	(2,042)	(51,958)
As of December 31, 2007	36,527	1,297,029
Revisions of previous estimates	6,738	412,155
Acquisitions of new reserves	513	38,008
Extensions and discoveries	1,728	241,596
Sales of reserves in place	(8)	(1,750)
Production	(2,334)	(87,402)
As of December 31, 2008	43,164	1,899,636
Revisions of previous estimates	8,826	(1,244,873)
Acquisitions of new reserves	56,342	104,046
Extensions and discoveries	8	8,890
Sales of reserves in place	(97)	(163)
Production	(2,894)	(87,461)
As of December 31, 2009	105,349	680,075
Proved developed reserves(2):		
As of December 31, 2006	10,994	308,296
As of December 31, 2007	12,532	590,358
As of December 31, 2008	15,342	851,357
As of December 31, 2009	38,327	592,777
Proved undeveloped reserves(2):		
As of December 31, 2006	14,181	542,412
As of December 31, 2007	23,995	706,671
As of December 31, 2008	27,822	1,048,279
As of December 31, 2009	67,022	87,298

(1) Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

(2) Our estimated proved reserves were determined using a 12-month average price for natural gas and oil for the year ended December 31, 2009 and year-end prices for natural gas and oil as of December 31, 2008, 2007 and 2006.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year to year are prepared in accordance with ASC Topic 932. The assumptions that underlie the computation of the standardized measure of discounted cash flows may be summarized as follows:

- the standardized measure includes the Company's estimate of proved oil, natural gas and natural gas liquids reserves and projected future production volumes based upon economic conditions;

- pricing is applied based upon 12-month average market prices at December 31, 2009 and year end prices for December 31, 2008 and December 31, 2007 adjusted for fixed or determinable contracts that are in existence at year-end. The calculated weighted average per unit prices for the Company's proved reserves and future net revenues were as follows:

	At December 31,		
	2009	2008	2007
Natural gas (per Mcf)	$ 3.41	$ 4.94	$ 6.46
Oil (per barrel)	$49.98	$39.42	$87.47

- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

The summary below presents the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure in ASC Topic 932.

	(In thousands)
As of December 31, 2007	
Future cash inflows from production	$11,578,381
Future production costs	(2,706,208)
Future development costs(a)	(1,640,500)
Future income tax expenses	(1,782,909)
Undiscounted future net cash flows	5,448,764
10% annual discount	(2,730,227)
Standardized measure of discounted future net cash flows	$ 2,718,537
As of December 31, 2008	
Future cash inflows from production	$11,092,154
Future production costs	(3,887,553)
Future development costs(a)	(2,153,506)
Future income tax expenses	(399,014)
Undiscounted future net cash flows	4,652,081
10% annual discount	(2,431,505)
Standardized measure of discounted future net cash flows	$ 2,220,576
As of December 31, 2009	
Future cash inflows from production	$ 7,582,670
Future production costs	(3,028,888)
Future development costs(a)	(938,272)
Future income tax expenses	—
Undiscounted future net cash flows	3,615,510
10% annual discount	(2,054,532)
Standardized measure of discounted future net cash flows	$ 1,560,978

(a) Includes abandonment costs.

The following table represents the Company's estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in thousands):

Changes in the Standardized Measure of Discounted Future Net Cash Flows Associated with Proved Oil and Gas Reserves

Present value as of December 31, 2006	$ 1,440,146
Changes during the year:	
Revenues less production and other costs	(351,863)
Net changes in prices, production and other costs	800,630
Development costs incurred	485,348
Net changes in future development costs	(723,943)
Extensions and discoveries	328,094
Revisions of previous quantity estimates	998,729
Accretion of discount	88,596
Net change in income taxes	(537,835)
Purchases of reserves in-place	155,051
Timing differences and other(a)	35,584
Net change for the year	1,278,391
Present value as of December 31, 2007	2,718,537
Changes during the year:	
Revenues less production and other costs	(719,091)
Net changes in prices, production and other costs	(1,747,962)
Development costs incurred	1,132,078
Net changes in future development costs	(1,152,018)
Extensions and discoveries	227,874
Revisions of previous quantity estimates	757,939
Accretion of discount	168,811
Net change in income taxes	794,001
Purchases of reserves in-place	47,767
Sales of reserves in-place	(2,076)
Timing differences and other(a)	(5,284)
Net change for the year	(497,961)
Present value as of December 31, 2008	2,220,576
Changes during the year:	
Revenues less production and other costs	(281,410)
Net changes in prices, production and other costs	(1,841,292)
Development costs incurred	201,467
Net changes in future development costs	1,075,246
Extensions and discoveries	8,671
Revisions of previous quantity estimates	(553,469)
Accretion of discount	109,512
Net change in income taxes	37,936
Purchases of reserves in-place	565,457
Sales of reserves in-place	(131)
Timing differences and other(a)	18,415
Net change for the year	(659,598)
Present value as of December 31, 2009	$ 1,560,978

(a) The change in timing differences and other are related to revisions in the Company's estimated time of production and development.

26. Quarterly Financial Results (Unaudited)

The Company's operating results for each quarter of 2009 and 2008 are summarized below (in thousands, except per share data).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2009:				
Total revenues	$ 159,013	$134,099	$ 134,855	$ 163,077
Loss from operations(2)	$(1,116,280)	$ (49,987)	$ (50,229)	$ (388,528)
Net loss(2)	$(1,154,854)	$ (91,170)	$(101,312)	$ (425,996)
Loss applicable to SandRidge Energy, Inc., common stockholders(2)	$(1,154,857)	$ (91,174)	$(104,132)	$ (434,240)
Net loss per share applicable to SandRidge Energy, Inc., common stockholders(1):				
Basic	$ (7.07)	$ (0.52)	$ (0.58)	$ (2.36)
Diluted	$ (7.07)	$ (0.52)	$ (0.58)	$ (2.36)
2008:				
Total revenues	$ 269,086	$378,050	$ 334,023	$ 200,655
(Loss) income from operations(2)	$ (62,811)	$ (11,795)	$ 401,287	$(1,664,828)
Net (loss) income(2)	$ (55,790)	$ (20,327)	$ 230,348	$(1,594,656)
(Loss) income (applicable) available to SandRidge Energy, Inc., common stockholders(2)	$ (66,207)	$ (26,993)	$ 230,346	$(1,594,658)
Net (loss) income per share (applicable) available to SandRidge Energy, Inc., common stockholders(1):				
Basic	$ (0.47)	$ (0.17)	$ 1.41	$ (9.78)
Diluted	$ (0.47)	$ (0.17)	$ 1.40	$ (9.78)

(1) Income (loss) per share available (applicable) to common stockholders for each quarter is computed using the weighted-average number of shares outstanding during the quarter, while earnings per share for the fiscal year is computed using the weighted-average number of shares outstanding during the year. Thus, the sum of income (loss) per share available (applicable) to common stockholders for each of the four quarters may not equal the fiscal year amount.

(2) Includes a full cost ceiling impairment of $388.9 million, $1,304.4 million and $1,855.0 million for the fourth quarter of 2009, first quarter of 2009 and fourth quarter of 2008, respectively.

SIGNATURES

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

SANDRIDGE ENERGY, INC.

By /s/ TOM L. WARD

Tom L. Ward,
Chairman of the Board and Chief Executive Officer

March 1, 2010

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Tom L. Ward, Richard J. Gognat and Justin P. Byrne, and each of them severally, his true and lawful attorney or attorneys-in-fact and agents, with full power to act with or without the others and with full power of substitution and resubstitution, to execute in his name, place and stead, in any and all capacities, any or all amendments to this report, and to file the same, with all exhibits thereto, and other 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 in the name of on behalf of the undersigned, in any and all capacities, each and every act and thing necessary or desirable to be done in and about the premises, to all intents and purposes and as fully as they might or could do in person, hereby ratifying, approving and confirming all that said attorneys-in-fact and agents or their substitutes may lawfully do or cause to be done by virtue hereof.

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

Signature	Title	Date
/s/ TOM L. WARD **Tom L. Ward**	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 1, 2010
/s/ DIRK M. VAN DOREN **Dirk M. Van Doren**	Chief Financial Officer and Executive Vice President (Principal Financial Officer)	March 1, 2010
/s/ RANDALL D. COOLEY **Randall D. Cooley**	Senior Vice President — Accounting (Principal Accounting Officer)	March 1, 2010
/s/ DAN JORDAN **Dan Jordan**	Director	March 1, 2010
/s/ BILL GILLILAND **Bill Gilliland**	Director	March 1, 2010
/s/ ROY T. OLIVER, JR. **Roy T. Oliver, Jr.**	Director	March 1, 2010
/s/ EVERETT R. DOBSON **Everett R. Dobson**	Director	March 1, 2010
/s/ D. DWIGHT SCOTT **D. Dwight Scott**	Director	March 1, 2010
/s/ JEFF SEROTA **Jeff Serota**	Director	March 1, 2010

INVESTOR INFORMATION

CORPORATE HEADQUARTERS

SandRidge Energy, Inc.

123 Robert S. Kerr Avenue

Oklahoma City, Oklahoma 73102-6406

(405) 429-5500

ANNUAL MEETING

Corporate Headquarters

June 4, 2010, at 10:00 a.m.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

PricewaterhouseCoopers LLP

1201 Louisiana, Suite 2900

Houston, Texas 77002

(713) 356-4000

TRANSFER AGENT & REGISTRAR

American Stock Transfer & Trust Company

Postal Address:

59 Maiden Lane

New York, New York 10038

Overnight Address:

Operations Center

6201 15th Avenue

Brooklyn, New York 11219

Shareholder Services:

(800) 937-5449 or (718) 921-8124

www.amstock.com/main/default.asp

INVESTOR RELATIONS CONTACT

Kevin R. White

Senior Vice President – Business Development

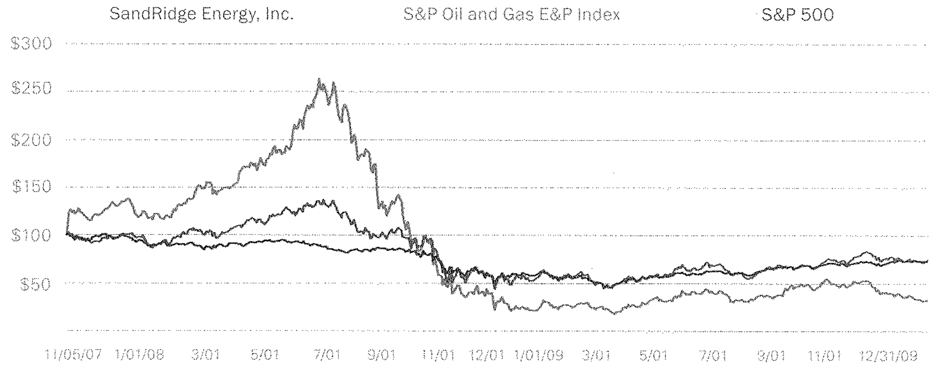
(405) 429-5515

investors@sdrge.com

PUBLICATIONS

A copy of SandRidge's annual report to the Securities and Exchange Commission (Form 10-K) and other publications are available upon request at no charge. For copies of this or any other SandRidge publication, please contact our Investor Relations department.

SANDRIDGE COMMON STOCK PRICE PERFORMANCE COMPARISON



The above graph compares the cumulative total return to shareholders on SandRidge Energy, Inc.'s (SD) common stock relative to the cumulative total returns of the S&P 500 Index and the S&P Oil and Gas Exploration and Production Index from November 5, 2007 (the date of SD's initial public offering) through December 31, 2009. The graph assumes that the value of the investment in the company's common stock and in each of the indexes was $100.00 on November 5, 2007.

STOCK PRICE

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "SD." The range of high and low sales prices for our common stock for the periods indicated, as reported by the NYSE, is as follows:

Quarter	2008 High	2008 Low
First	$ 41.05	$28.50
Second	$ 69.00	$ 37.88
Third	$ 69.41	$ 17.46
Fourth	$ 19.54	$ 4.85

Quarter	2009 High	2009 Low
First	$ 8.79	$ 4.49
Second	$11.84	$ 6.31
Third	$15.00	$ 7.44
Fourth	$14.08	$ 7.97

FORWARD-LOOKING STATEMENTS

This annual report includes "forward-looking statements" 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 statements express a belief, expectation or intention and are generally accompanied by words that convey projected future events or outcomes. The forward-looking statements include statements about SandRidge Energy, Inc.'s future operations, rig count, projected production volumes, projections about the overall supply of natural gas in the United States, projections and estimates of the average prices the company expects to realize for the oil and natural gas it produces, estimates of reserve and resource volumes, reserve and resource values and potential, future drilling locations, expected construction and start-up of and deliveries to the Century Plant, expected CO_2 processing capacity, 3-D seismic program, potential development, acquisition and exploration strategies, potential extensions of field limits, projections of amounts available for borrowing under its revolving credit facility, projected finding costs and other expenses, rates of return, revenue, earnings, cash flow and capital expenditures and future strategies related to levels of indebtedness, capital raising activities and hedging transactions. We have based these forward-looking statements on our current expectations and assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with our expectations and predictions is subject to a number of risks and uncertainties, including the volatility of oil and natural gas, our success in discovering, estimating, developing and replacing oil and natural gas reserves, the availability and terms of capital, our level of indebtedness, the ability of counterparties to our transactions to meet their obligations, the execution of our anticipated development, acquisition and exploration strategies, including the consummation of potential acquisitions, our timely execution of hedge transactions, credit conditions of global capital markets, the amount and timing of future development costs, construction risks related to the Century Plant, the availability and demand for alternative energy sources, regulatory changes, including those related to carbon dioxide, and other factors, many of which are beyond our control. We refer you to the discussion of risk factors in Part I, Item 1A - "Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2009 and in comparable "risk factors" sections of our Quarterly Reports on Form 10-Q filed after the date of the Form 10-K. All of the forward-looking statements made in this annual report are qualified by these cautionary statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on our company or our business or operations. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in the forward-looking statements. We undertake no obligation to update or revise any forward-looking statements.

The SEC permits oil and natural gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves, as each is defined by the SEC. Under SEC rules, proved reserve estimates are considered reasonably certain. Probable reserve estimates are as likely as not to be achieved and possible reserve estimates might be achieved but only under more favorable circumstances than are likely, making each of them inherently less certain than proved reserve estimates and subject to greater risk of being actually realized by the company. This annual report includes a table demonstrating the sensitivity of the company's proved oil and natural gas reserves to price fluctuations by comparing the reserves calculated under the price assumptions required by current U.S. Securities and Exchange Commission ("SEC") rules to (1) spot prices at December 31, 2009, and (2) the 10-year average NYMEX strip prices as of December 31, 2009. The reserves presented under these alternative price assumptions are not calculated in accordance with current SEC rules, and they have not been reviewed by independent petroleum engineers. These estimates are by their nature more speculative than estimates of proved, probable or possible reserves and, accordingly, are subject to substantially greater risk of being actually realized by the company. For a discussion of the company's proved reserves, as calculated under current SEC rules, we refer you to the company's Annual Report on Form 10-K referenced above, which is available on our website at www.sandridgeenergy.com and on the SEC's website at www.sec.gov.

SandRidge

energy to go further

SandRidge Energy, Inc.

123 Robert S. Kerr Avenue
Oklahoma City, Oklahoma 73102-6406

www.SandRidgeEnergy.com