SANDRIDGE ENERGY INC
Form 10-K
February 26, 2009

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

Form 10-K

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2008**
	OR
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

Commission File Number: 1-33784

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

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

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

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

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2008 was approximately $8.0 billion based on the closing price as quoted on the New York Stock Exchange. As of February 20, 2009, there were 167,625,519 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2009 Annual Meeting of Shareholders are incorporated by reference in Part III.

SANDRIDGE ENERGY, INC.

2008 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. We are focused on the exploration and exploitation of our significant holdings in the West Texas Overthrust, which we refer to as the WTO, a natural gas prone geological region in Pecos County and Terrell County, Texas, where we have operated since 1986 and currently have 655,926 net acres under lease. The WTO includes the Piñon Field as well as the Allison Ranch, South Sabino, Thistle, Big Canyon and McKay Creek exploration areas.

We have assembled an extensive natural gas and crude oil property base on which we have identified approximately 7,900 potential drilling locations as of December 31, 2008, including approximately 3,100 locations in the WTO. As of December 31, 2008, our estimated proved reserves, approximately 96% of which were prepared by third party engineers, were 2,158.6 Bcfe, of which 88% were natural gas. As of December 31, 2008, we had 2,059 gross (1,515.8 net) producing wells, substantially all of which we operate, and we had natural gas and oil interests in 1,655,956 gross (1,247,664 net) leased acres. Additionally, we averaged 29 rigs drilling in the WTO, five rigs drilling in East Texas, three rigs drilling in the Mid-Continent and three rigs drilling in other areas during 2008. We had nine rigs drilling in the WTO, five rigs drilling in East Texas, one rig drilling in Oklahoma and two rigs drilling in other areas as of December 31, 2008.

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 drilling rig business, Lariat Services, Inc. (Lariat). As of December 31, 2008, our drilling rig fleet consisted of 43 rigs 31 rigs owned directly by us and 12 rigs owned by Larclay, L.P. (Larclay), a limited partnership in which we have a 50% interest. Currently, 28 of our owned rigs and 11 of the Larclay rigs are 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 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

During the second half of 2008, unprecedented levels of volatility in the financial and commodity markets made it necessary for us to reduce and refocus our exploration and development activities, reduce our budget for capital expenditures, explore the potential sale of certain assets and seek additional capital.

Private Placement of Convertible Perpetual Preferred Stock. In January 2009, we completed a private placement of 2,650,000 shares of 8.5% convertible perpetual preferred stock to qualified institutional buyers eligible under Rule 144A under the Securities Act of 1933, as amended (the Securities Act). The placement included 400,000 shares of convertible perpetual preferred stock issued upon the full exercise of the initial purchasers option to cover over-allotments. Net proceeds from the offering were approximately $243.9 million after deducting offering expenses of approximately $8.0 million. We used the net proceeds of the offering to repay outstanding borrowings under our senior credit facility and for general corporate purposes.

Each share of the convertible perpetual preferred stock has a liquidation preference of $100 and is entitled to an annual dividend of $8.50 payable semi-annually in cash, common stock or any combination thereof, beginning on February 15, 2010. No dividends will accrue or accumulate prior to August 15, 2009. Additionally, each share is initially convertible into 12.48 shares of our common stock, at the holder s option, at any time on or after April 15, 2009 based on an initial conversion price of $8.01 and subject to customary adjustments in certain circumstances.

Marketing of Midstream Assets. In January 2009, we announced our intent to offer for sale certain of our gas gathering and related assets located in the WTO. This process is ongoing as of the date of this filing.

2009 Capital Expenditure Budget. We are introducing a 2009 production guidance range of 110.0 Bcfe to 120.0 Bcfe based on a capital expenditure guidance range of $500.0 million to $700.0 million. Based on the current and anticipated near-term drilling activity and associated expenditures, it is currently expected that full year results will trend toward the lower half of these ranges.

Drilling Activity. We began to decrease the number of rigs running on our properties during December 2008 in preparation for reduced 2009 activity levels. At February 20, 2009, we had 9 rigs running compared to a high of 47 rigs operating in the second quarter of 2008.

East Texas/North Louisiana Haynesville Shale Play: We control approximately 36,000 acres in the developing Haynesville shale play of East Texas and North Louisiana. We drilled two vertical test wells within the Oakhill field area in Rusk County to evaluate the potential for Haynesville shale production. The initial well had a total of 260 feet of Haynesville shale thickness and tested at a rate of 1.5 MMcfe per day. The second well encountered 288 feet of shale thickness and is awaiting completion.

Business Strategy

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

Grow Through Exploration and Drilling and Development 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, where we owned interests in 777,475 gross (655,926 net) acres at December 31, 2008 and operated up to 35 rigs during 2008 (nine as of December 31, 2008). We have identified approximately 3,100 potential drilling locations in the WTO and believe that we will be able to expand the number of drilling locations in the WTO through exploratory drilling and use of our 3-D seismic technology.

Apply Technological Improvements to Our Exploration and Development Program. We use our 3-D seismic acquisition program and our enhanced interpretation technologies to achieve high drilling and exploration success rates. We strive to maximize value by minimizing time from spud to first sales with advanced drilling, completion and production methods that historically have not been widely used in the WTO.

Seek Opportunistic Acquisitions in Our Core Geographic Areas. Since January 2006, through acquisitions and leasing activities, we have tripled our net acreage position in the WTO. We intend to continue to seek other opportunities to optimize and enhance our exploratory acreage position in the WTO and other strategic areas.

Reduce Costs, Enhance Returns and Maintain Operating Flexibility by Controlling Operations. We operate 97.3% of our production in the WTO, East Texas, the Gulf Coast area and the Mid-Continent 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.

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Our Businesses and Primary 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. We operate substantially all of our wells in the WTO. We also have significant operated leasehold positions in the Cotton Valley Trend in East Texas, the Gulf Coast area and the Mid-Continent, as well as other non-core operating areas.

The following table identifies certain information concerning our exploration and production business as of December 31, 2008 unless otherwise noted:

	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
Area							
WTO	1,342.6	1,223.2	173.8	21.2	777,475	655,926	3,121
East Texas	399.3	462.0	46.1	23.8	59,564	29,989	1,567
Gulf Coast	75.4	148.5	24.8	8.3	60,059	34,764	43
Mid-Continent	93.0	146.8	38.8	6.6	583,333	417,573	2,474
Other:							
Gulf of Mexico	44.5	32.8	6.9	17.6	76,559	37,434	67
Other West Texas	87.3	148.7	20.1	11.9	60,632	39,236	441
Tertiary recovery-West Texas	116.0	95.1	3.1	102.1	9,064	8,195	67
Other	0.5	1.4	0.1	14.3	29,270	24,547	151
Total	2,158.6	2,258.5	313.7	18.9	1,655,956	1,247,664	7,931

(1) PV-10 generally differs from Standardized Measure of Discounted Net Cash Flows, or Standardized Measure, because it does not include the effects of income taxes on future net revenues. For a reconciliation of PV-10 to Standardized Measure as of December 31, 2008, see Proved Reserves. Our Standardized Measure was $2.2 billion at December 31, 2008.

(2) Average daily net production for the month of December 2008.

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 discouraged exploration of the area. Our access to and control of the necessary infrastructure combined with application of modern seismic techniques allow us to continue to identify further exploration and development opportunities in the WTO.

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3-D Seismic Program. In May 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, 2008, we had acquired 1,292 square miles of 3-D seismic data, of which 1,050 square miles had been processed and is currently being interpreted.

Piñon Field. The Piñon Field, located in Pecos County, is our most significant producing field, accounting for 62.2% of our proved reserve base as of December 31, 2008 and approximately 68% of our 2008 exploration and development expenditures (including land and seismic acquisitions). The Piñon Field lies along the leading edge of the WTO. The primary reservoirs are the Tesnus sands (depths ranging from 3,500 to 5,000 feet), the Upper Caballos chert (depths ranging from 5,000 to 8,000 feet) and the Lower Caballos chert (depths ranging from 7,000 to 10,000 feet). During 2008, 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, 2008, our estimated proved natural gas and oil reserves in the Piñon Field were 1,342.6 Bcfe, 54.8% 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, 2008 included 660 producing wells and a 96.0% average working interest in the producing area of the Piñon Field. We were operating nine drilling rigs in the Piñon Field as of December 31, 2008 and we drilled 252 wells in this field during 2008.

West Texas Overthrust Prospects. Through our regional exploratory efforts, to date we have identified five exploration areas: Allison Ranch, South Sabino, Thistle, Big Canyon and McKay Creek. 3-D seismic data has been recently acquired over these five exploration areas, which should allow us to further develop these prospective areas for future exploration.

West Texas Overthrust Development. The following table provides information concerning development opportunities in the WTO:

Estimated Net PUD Reserves (Bcfe)(1)	**Estimated Gross PUD Reserves (Bcfe)(1)**	**Gross PUD Drilling Locations(1)**	**Total Gross Drilling Locations(1)**	**2008 Year End Rigs Working**
735.5	1,024.1	744	3,121	9

(1) As of December 31, 2008.

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) and associated compression and pipeline facilities 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 800.0 MMcf per day of natural gas and is expected to be completed in two phases with the first phase coming on line in the second quarter of 2010 and the second phase coming on line in the second quarter 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.

High CO_2 Treating. 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 will expand CO_2 treating capacity in the area and will allow us to accelerate the development of the Warwick thrust.

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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, 2008, we held interests in 59,564 gross (29,989 net) acres in East Texas. At that time, our estimated net proved reserves in East Texas were 399.3 Bcfe, with net production of approximately 46.1 MMcfe per day for the month of December 2008. 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 54 wells (53.3 net wells) in the Cotton Valley Trend in 2008. As of December 31, 2008, we had five rigs running in this region and expect to drill an additional 29 wells during 2009.

Gulf Coast

As of December 31, 2008, we owned natural gas and oil interests in 60,059 gross (34,764 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, 2008, our estimated net proved reserves in the Gulf Coast area were 75.4 Bcfe, with net production of approximately 24.8 MMcfe per day for the month of December 2008.

Mid-Continent

We own interests in properties in Oklahoma, Arkansas and southern Kansas that make up our Mid-Continent area. As of December 31, 2008, we held interests in approximately 583,333 gross (417,573 net) leasehold and option acres in these areas. As of December 31, 2008, our estimated proved reserves in the Mid-Continent area were 93.0 Bcfe, based on estimates prepared by our internal engineers. Our average daily net production for the month of December 2008 was approximately 38.8 MMcfe per day.

Other Areas

Gulf of Mexico. As of December 31, 2008, we owned natural gas and oil interests in 76,559 gross (37,434 net) acres in state and federal waters off the coast of Texas and Louisiana. As of December 31, 2008, our estimated net proved reserves in the Gulf of Mexico were 44.5 Bcfe, with net production of approximately 6.9 MMcfe per day for the month of December 2008. 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.

Other West Texas. Other non-tertiary assets we own in West Texas, outside of the WTO, include our Brooklaw Field and the Goldsmith Adobe Unit in the Permian Basin. As of December 31, 2008, we owned interests in 60,632 gross (39,236 net) acres in these prospects. As of December 31, 2008, our estimated net proved reserves were 87.3 Bcfe with net production of approximately 20.1 MMcfe per day for the month of December 2008. We have identified 441 potential drilling locations in these fields, including 134 proved undeveloped locations.

Tertiary Oil Recovery

Wellman Unit. The Wellman Unit, located in the Wellman Field in Terry County, Texas produces from the Canyon Reef limestone formation of Permian age from an average depth of 9,500 feet. The Wellman Unit covers approximately 2,120 acres, 1,200 of which are well-suited for both water and CO_2 floods. The Wellman Field has been partially CO_2 flooded and water flooded to produce 83.8 Mmboe to date. We re-initiated injection of CO_2 in November 2005. Our injection rate of CO_2 averaged 9.5 MMcf per day in 2008 and we expect to reach an average injection rate of 29.4 MMcf per day over the next 10 years. The Wellman Field has responded to this injection, and we averaged net oil production of 396 Bbls per day of new oil in December 2008. As of December 31, 2008, net proved reserves attributable to the Wellman Unit were 6.6 Mmboe. We also own a CO_2 recycling plant at this unit with a capacity of 28.0 MMcf per day. The plant includes 6,000 horsepower of CO_2 compression and 4,850 horsepower of compression, which is sufficient to handle the recycling of the CO_2 that will be produced in association with the production of these reserves.

George Allen Unit. The George Allen Unit, located in Gaines County, Texas covers 800 gross acres in the George Allen Field and produces from the San Andres formation from an average depth of 4,950 feet. We have also leased an additional 320 acres adjacent to the George Allen Unit to the south. The field is located within the greater Wasson area, which contains seven active CO_2 floods including the largest in the world, the Denver Unit. The George Allen Unit has produced 1.6 Mmboe to date, but it also contains a significant transition zone, which has been proven to be a tertiary oil target at the nearby Denver Unit. We are currently evaluating a nine-pattern pilot project. CO_2 injection began in December 2007 following implementation of the first two patterns and averaged approximately 2.0 MMcf per day during 2008. We are currently evaluating the remaining seven flood patterns for CO_2 injection. CO_2 injection into the nine patterns is expected to reach 15.0 MMcf per day when fully developed. As of December 31, 2008, net proved reserves attributable to the George Allen Field were 7.6 Mmboe.

South Mallet Unit. The South Mallet Unit, located in Hockley County, Texas, covers 3,540 gross acres in the Slaughter/Levelland Field complex and produces from the San Andres formation from an average depth of 5,000 feet. These fields are some of the largest in West Texas and currently have fourteen active CO_2 floods and six more at various stages of readiness. The South Mallet Unit has produced 27.9 Mmboe to date. We are currently evaluating five flood patterns for CO_2 injection. We expect to reach an ultimate CO_2 injection rate of approximately 18 MMcf per day into thirteen patterns. As of December 31, 2008, net proved reserves attributable to the South Mallet Unit were 5.0 Mmboe.

Jones Ranch Area. Several miles west of the George Allen Unit, in Gaines County, SandRidge Tertiary has acquired various leases in the Jones Ranch Area. These leases, covering approximately 2,400 gross acres, produce from various depths and formations. We are evaluating these leases for both conventional development and tertiary potential.

Proved Reserves

The following historical estimates of net proved natural gas and oil reserves are based on reserve reports as of December 31, 2008, December 31, 2007 and December 31, 2006, 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 were based on our current drilling schedule and prices at December 31, 2008, and we estimate that 94.1% of our current proved undeveloped reserves will be developed by 2011 and all of our current proved undeveloped reserves will be developed by 2012. 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.

Netherland, Sewell & Associates, Inc., independent oil and gas consultants, prepared the reports of estimated proved reserves of natural gas and oil for our net interest in certain natural gas and crude oil properties, which constituted approximately 90.2% of our total proved reserves as of December 31, 2008, approximately 89% of our total proved reserves as of December 31, 2007 and 92% of our total proved reserves as of December 31, 2006. DeGolyer and MacNaughton prepared the reports of estimated proved reserves (our tertiary oil reserves located in West Texas), for SandRidge Tertiary, LLC, formerly PetroSource Production Company, LLC, which constituted approximately 5.4% of our total proved reserves as of December 31, 2008, approximately 8% of our total proved reserves as of December 31, 2007 and approximately 7% of our total proved reserves as of December 31, 2006. The remaining 4.4%, 3% and 1% of our estimated proved reserves as of December 31, 2008, 2007 and 2006 were based on internally prepared estimates.

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	December 31, 2008	2007	2006
Estimated Proved Reserves(1)			
Natural gas (Bcf)(2)	1,899.6	1,297.0	850.7
Oil (MmBbls)	43.2	36.5	25.2
Total (Bcfe)	2,158.6	1,516.2	1,001.8
PV-10 (in millions)(3)	$ 2,258.5	$ 3,550.5	$ 1,734.3
Standardized Measure of Discounted Net Cash Flows (in millions)(4)	$ 2,220.6	$ 2,718.5	$ 1,440.2

(1) Our estimated proved reserves and the future net revenues, PV-10, and Standardized Measure of Discounted Net Cash Flows were determined using year-end prices for natural gas and oil as of December 31, 2008, 2007 and 2006. The calculated weighted average prices were $4.94 per Mcf of natural gas and $39.42 per barrel of oil at December 31, 2008, $6.46 per Mcf of natural gas and $87.47 per barrel of oil at December 31, 2007 and $5.32 per Mcf of natural gas and $54.62 per barrel of oil at December 31, 2006.

(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. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity. The following table provides a reconciliation of our Standardized Measure to PV-10:

	At December 31, 2008	2007 (In millions)	2006
Standardized Measure of Discounted Net Cash Flows	$ 2,220.6	$ 2,718.5	$ 1,440.2
Present value of future income tax discounted at 10%	37.9	832.0	294.1
PV-10	$ 2,258.5	$ 3,550.5	$ 1,734.3

(4) The Standardized Measure of Discounted Net Cash Flows 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 because Standardized Measure includes the effect of future income taxes.

Proved oil and gas reserves are the estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions such as prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (i) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (ii) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

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Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include the following:

- oil that may become available from known reservoirs but is classified separately as indicated additional reserves;
- oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors;
- oil, natural gas and natural gas liquids that may occur in undrilled prospects; and
- oil, natural gas and natural gas liquids that may be recovered from oil shales, coal, gilsonite and other such sources.

Production and Price History

The following tables set forth information regarding our net production of oil, natural gas 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,		
	2008	**2007**	**2006**
Production Data:			
Natural gas (MMcf)	87,402	51,958	13,410
Oil (MBbls)(1)	2,334	2,042	322
Combined equivalent volumes (MMcfe)	101,405	64,211	15,342
Average daily combined equivalent volumes (MMcfe/d)	277.1	175.9	42.0

	Year Ended December 31,		
	2008	**2007**	**2006**
Average Prices(2):			
Natural gas (per Mcf)	$ 7.95	$ 6.51	$ 6.19
Oil (per Bbl)(1)	$ 91.54	$ 68.12	$ 56.61
Combined equivalent (per Mcfe)	$ 8.96	$ 7.45	$ 6.60

(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.

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	Year Ended December 31,		
	2008	2007	2006
Expenses per Mcfe:			
Lease operating expenses:			
Transportation	$ 0.11	$ 0.12	$ 0.22
Processing, treating and gathering(1)	0.33	0.28	0.37
Other lease operating expenses	1.13	1.25	1.70
Total lease operating expenses	$ 1.57	$ 1.65	$ 2.29
Production taxes	$ 0.30	$ 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.

Productive Wells

The following table sets forth the number of productive wells in which we owned a working interest at December 31, 2008. 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.

Area	Gross	Net
WTO	660	632.7
East Texas	232	218.4
Gulf Coast	141	86.2
Mid-Continent	611	242.5
Other:		
Gulf of Mexico	42	21.2
Other West Texas	283	272.9
Tertiary recovery West Texas	43	40.9
Other	47	1.0
Total	2,059	1,515.8

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Developed and Undeveloped Acreage

The following table sets forth information regarding our developed and undeveloped acreage at December 31, 2008:

	Developed Acreage(1)		Undeveloped Acreage(2)	
Area	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
WTO	19,394	18,797	758,081	637,129
East Texas	31,328	23,945	28,236	6,044
Gulf Coast	44,250	24,820	15,809	9,944
Mid-Continent	92,016	54,059	491,317	363,514
Other:				
Gulf of Mexico	71,128	32,003	5,431	5,431
Other West Texas	32,432	23,252	28,200	15,984
Tertiary recovery West Texas	9,064	8,195		
Other	163	38	29,107	24,509
Total	299,775	185,109	1,356,181	1,062,555

(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, 2008 the expiration periods of the gross and net acres that are subject to leases in the acreage summarized in the above table.

	Acres Expiring	
Twelve Months Ending	**Gross**	**Net**
December 31, 2009	222,258	145,691
December 31, 2010	240,761	183,925
December 31, 2011	429,803	320,767
December 31, 2012 and later	404,456	352,492
Other(1)	68,581	61,968

Total	1,365,859	1,064,843

(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

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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, 2008, we had 54 wells in process.

	2008				2007				2006			
	Gross	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**
evelopment:												
roductive	398	98.5%	372.4	98.5%	281	99.3%	244.4	99.5%	82	94%	50.8	95%
ry	6	1.5%	5.7	1.5%	2	0.7%	1.3	0.5%	5	6%	2.5	5%
otal	404	100%	378.1	100%	283	100%	245.7	100%	87	100%	53.3	100%
xploratory:												
roductive	48	96%	46.4	95.9%	27	82%	24.3	84%	19	76%	13.0	72%
ry	2	4%	2.0	4.1%	6	18%	4.7	16%	6	24%	5.0	28%
otal	50	100%	48.4	100%	33	100%	29.0	100%	25	100%	18.0	100%
otal:												
roductive	446	98.2%	418.8	98.2%	308	98%	268.7	98%	101	90%	63.8	89%
ry	8	1.8%	7.7	1.8%	8	2%	6.0	2%	11	10%	7.5	11%
	454	100%	426.5	100%	316	100%	274.7	100%	112	100%	71.3	100%

Drilling Rigs

The following table sets forth information with respect to the rigs operating on our acreage as of December 31, 2008.

Area	**Owned(1)**	**Third-Party**
WTO	9	
East Texas	2	3
Gulf Coast		
Mid-Continent		1
Other West Texas	2	
Total	13	4

(1) Includes rigs owned by Lariat and by Larclay.

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. During 2008 and 2007, we sold our production to over twenty different purchasers, one of which, Plains Energy, accounted for approximately 10% and 11%, respectively, of our total revenue. Given the number of 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 crude 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 in West Texas are described below.

Drilling Operations

We drill for our own account in the WTO 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. In addition, we own a 50% interest in a limited partnership, Larclay, which owns and operates drilling rigs. Our rig fleet, including rigs owned by Larclay, is designed to drill in our specific areas of operation and has an average horsepower of over 800 and an average depth capacity of greater than 10,500 feet. As of December 31, 2008, our drilling rig fleet consisted of 39 operational rigs, 28 of which we owned directly and 11 of which were owned by Larclay. As of December 31, 2008, 13 of our rigs were working on properties that we operated.

In 2005, we ordered 22 rigs from Chinese manufacturers for an aggregate purchase price of $126.4 million, which included the cost of assembling and equipping the rigs in the United States. Due in part to the shortage of experienced drilling employees and various operational challenges, we deemed it prudent to retrofit five of these rigs to a conventional operation. The last of the five rigs to be retrofitted became operational in the second quarter of 2008.

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

	Year Ended December 31,		
	2008	**2007**	**2006**
Number of operational rigs owned at end of period	28	25	25
Average number of operational rigs owned during the period	27.6	26.0	21.9
Average drilling revenue per day per rig working for third parties(1)(2)	$ 14,217	$ 21,468	$ 24,646

(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, 2008:

	SandRidge	Operating for Third Parties	Idle	Operational(1)
Lariat	13	3	12	28
Larclay	0	1	10	11
Total	13	4	22	39

(1) Excludes two Lariat rigs that were being refurbished, one Lariat rig that was non-operational and one Larclay rig that has not been assembled.

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Oil Field Services

Our oil field services business began in 1986 and conducts operations that complement our drilling services operations. These services include providing drilling rigs, pulling units, trucking, rental tools, location and road construction and roustabout services to us and our subsidiaries as well as to third parties. Approximately 11% of our oil field services in 2008 were performed for third parties, a decline from the approximately 28% in 2007 due to an increase in the average number of our rigs that were operating on our properties, an increase in our ownership interest in our natural gas and crude oil properties and a decline in average revenue earned per day for rigs working for third parties. Our capital expenditures for 2008 related to our oil field services were $52.9 million and we have budgeted a range of $10.0 million to $20.0 million in capital expenditures in 2009 for oil field services.

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 daywork or turnkey 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.

Our Customers

We perform approximately two-thirds of our drilling services in support of our exploration and production business and approximately one-third for other operators in West Texas. For the year ended December 31, 2008, we generated revenues of $10.7 million for drilling services performed for third parties, with Pioneer Natural Resources accounting for approximately $9.3 million of those revenues.

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 business, but also service other natural gas and oil companies. The following tables set forth information regarding our primary midstream assets as of December 31, 2008:

Gas Plants (West Texas)	**Plant Capacity (MMcf/d)**	**Average Utilization(1)**	**Third-Party Usage**
Pike s Peak	81	98%	<1%
Grey Ranch(2)	160	89%	16%

(1) Average utilization for the year ended December 31, 2008.

(2) We experienced a fire at our Grey Ranch plant located in Pecos County, Texas on June 27, 2008. The plant was shut down for repairs until its return to service October 31, 2008. Prior to the fire, the plant had 95 MMcf/d of treating capacity. As of December 31, 2008, the plant was operating with the expanded capacity of 160 MMcf/d

as a result of expansions made to the plant during the repair of fire damage.

SandRidge CO_2 Facilities (West Texas)	CO_2 Compression Capacity (MMcf/d)	Average Utilization(1)
Pike s Peak	38	78%
Mitchell	26	95%
Grey Ranch(2)	100	19%
Terrell	38	64%

(1) Average utilization for the year ended December 31, 2008.

(2) Includes the period that the Grey Ranch plant was shut down and operating at limited capacity due to a fire that occurred on June 27, 2008.

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West Texas

In Pecos County, we operate and own the Pike s Peak gas treating plant, which has the capacity to treat 81 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 2010. Our 50% partner, Southern Union, operates the plant. 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 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 65 MMcf per day of treating capacity at Anadarko Petroleum Corporation s Mitchell Plant under a long-term fixed fee arrangement.

We also operate or own approximately 653 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, 2008, we owned and operated approximately 80,000 horsepower of gas compression in West Texas. We anticipate installing an additional 20,000 horsepower in 2009.

Other Areas

As of December 31, 2008, we owned approximately 110 miles of pipeline gathering systems and operated more than 11,000 horsepower of natural gas compression in East Texas and approximately 44 miles of pipeline gathering systems in the Gulf Coast area.

In May 2008, we completed the sale of substantially all of our assets located in the Piceance Basin of Colorado, including gathering and compression systems as well as undeveloped acreage, working interests in wells and other facilities related to natural gas and oil wells.

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 2008, we spent approximately $164.0 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 79 MMcf per day in additional treating capacity. We anticipate adding approximately 60 MMcf per day in additional treating capacity in 2009. We have budgeted approximately $65.0 million in 2009 capital expenditures for our midstream gas services and other segments.

Marketing

Through Integra Energy LLC, (Integra Energy), our wholly owned subsidiary, we buy and sell the 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 MmBtu per day of firm transportation service subscribed on the Oasis Pipeline and 75 MmBtu per day on the Mid-Continent Express Pipeline for a portion of our Piñon Field production for 2009. The commitment to the Mid-Continent Express Pipeline commences upon completion of its construction, currently estimated to be in the summer of 2009.

Other Operations

Our CO_2 capturing operations are conducted through SandRidge CO_2. As of December 31, 2008, SandRidge CO_2 owned 231 miles of CO_2 pipelines in West Texas with approximately 88,000 horsepower of owned and leased CO_2 compression available and approximately 54,000 horsepower currently operational. The captured CO_2 is primarily used and sequestered in tertiary oil recovery operations. As of December 31, 2008, SandRidge CO_2 was capturing approximately 85.0 MMcf per day of CO_2. We delivered the majority of this to Occidental Permian Ltd. (Occidental) and Chevron Corp. In December 2008, we captured and sold an average of 67.4 MMcf of CO_2 per day and utilized 15.1 MMcf per day in our equity projects.

Future regulation of greenhouse gas emissions may provide the Company 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 1.6 million metric tonnes of CO_2 per year which is sequestered in enhanced oil recovery projects. The captured CO_2 may prove beneficial to us if the 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 200,000 tonnes were sold on the voluntary market during 2008. See Environmental Regulations Future Laws and Regulations.

Competition

We believe that our leasehold acreage position, oil field service 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 are competing with 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 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 crude 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 sometimes awarded on the basis of competitive bids.

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, as is the case in the current economic environment. 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. Seasonal anomalies such as mild winters or cool summers sometimes lessen this fluctuation. 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 the environmental laws and regulations that could have a material impact on the oil and gas industry.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or 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 owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of 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, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the United States Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of 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 that we expect will cause us to incur increased capital and operating costs at new and existing facilities. We have committed approximately $3.5 million to compressor engine emission reduction projects to enable compliance at our Grey Ranch compression station and our Pikes Peak treating plant. Additionally, our midstream operations have implemented a voluntary compliance audit under the Texas Environmental Health and Safety Audit Privilege Act. Substantial additional expenses and capital costs may be required in 2009 and beyond for us to maintain or achieve compliance with current and future laws governing air emissions.

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, or 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 a variety of regulations 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, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency 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.

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. 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, or 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 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 crude 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 oil, natural gas 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 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, or 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 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, or 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.

FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. 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, unregulated, 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 recently has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point-of-sale locations.

Employees

As of December 31, 2008, we had 2,094 full-time employees and one part-time employee, including more than 210 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of our 2,095 employees, 528 are located at our headquarters in Oklahoma City, Oklahoma, and the remaining employees are working in our various field offices and at our drilling sites.

Offices

In July 2007, we purchased property in downtown Oklahoma City, Oklahoma, which serves as our corporate headquarters. We also own office and shop space in Fort Stockton, Midland and Odessa, Texas. As of December 31, 2008, we leased 57,417 square feet of office space in Oklahoma City, Oklahoma. The term of the lease expires in August 2009. In addition, we lease or sublease office space in Oklahoma, Louisiana and Texas.

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 hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

CO_2. Carbon dioxide.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

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

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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 and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

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%.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area 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. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as:

Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as:

The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (C) oil, natural gas and natural gas liquids, that may occur in undrilled prospects; and (D) oil, natural gas and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or crude oil that is confined by impermeable rock or water barriers and is 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 and asset retirement obligations 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 commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

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 the fourth quarter of 2008, 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, 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. As a result, we do not anticipate that Lehman Brothers will 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.

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

We utilize the full cost method of accounting for costs related to our natural gas and crude 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 prices for natural gas and oil in effect at the end of the quarter, 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, 2008 resulted in a non-cash impairment charge of $1,855.0 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 writedowns of capitalized costs of our natural gas and crude oil properties and non-cash charges against future earnings. The amount of such future writedowns and non-cash charges could be substantial. If natural gas and oil commodity prices remain at these current levels or decline further through the end of the first quarter of 2009, we estimate we would have a further reduction in our asset carrying value for our natural gas and crude oil properties.

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, 2008, our total indebtedness was $2.4 billion, which represented approximately 75% of our total capitalization. Our substantial level of indebtedness 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 competitive 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 will materially affect the quantities and present value of our reserves.

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. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing 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 prices and costs in effect on the last day of the reporting period. 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;
- 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 crude 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, 2008, only 1,514 of our 7,931 identified potential future well locations were attributed 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

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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 oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas 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 2008, we participated in drilling a total of 454 gross wells, of which eight were identified as dry holes. If we drill additional wells that we identify as dry holes in our current and future prospects, our drilling success rate may decline and materially harm our business. In sum, 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 the WTO and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 54.8% of the estimated proved reserves that we owned or had under lease in the WTO as of December 31, 2008 were proved undeveloped reserves and 56.3% 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 the WTO, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2008, approximately 62% of our proved reserves and approximately 55% of our production were located in the WTO. 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 12% 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 midstream gas services operations, due to the decline in production from existing wells, depressed commodity prices or otherwise, would adversely affect our revenues and cash flow for our midstream gas services segment.

The profitability of our midstream business is materially impacted by the volume of natural gas we gather, transport and treat at our facilities. Most of the reserves supporting our 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 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. Failure to connect new wells to our 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 ability to connect to new wells will be dependent on the level of drilling activity in our areas of operations and competitive market factors. Because of our reduced capital expenditures budget for 2009, we expect that we will connect fewer new wells in the near future, which in turn may result in our midstream assets handling lower natural gas volumes than previously projected. Any material decrease in the volume of natural gas handled by our midstream assets would reduce our revenues, operating income and cash flows.

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.

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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 holes 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.

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.

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, asset sales, cash flow from operations 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 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 facilities, 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 crude 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 required under 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 or 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, 2008, we had natural gas and crude oil derivative contracts, excluding basis swaps, of 79.8 Bcfe at an average price of $8.60 per Mcfe in place for 2009 and 68.4 Bcfe at an average price of $7.77 per Mcfe in place for 2010. The Company also had natural gas basis swaps in place through 2011 for 125.9 Bcf at an average price of $0.73 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 crude 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 crude 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 reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a

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project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local 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 remediate our 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, President Obama has expressed support for, and it is anticipated that the current session of Congress will consider legislation to restrict or regulate emissions of greenhouse gases. 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 like 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 guaranty that, once the Century Plant is constructed, we will be able to find, produce

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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.

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 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.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Information regarding our properties is included in Item 1 and in Note 6 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. ***Submission of Matters to a Vote of Security Holders***

Not applicable.

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 period from November 6, 2007, when trading of our common stock commenced, through December 31, 2008 as reported by the NYSE, is as follows:

	High	Low
2007		
Fourth Quarter (from November 6, 2007 through December 31, 2007)	$ 36.11	$ 29.53
2008		
First Quarter	$ 41.05	$ 28.50
Second Quarter	$ 69.00	$ 37.88
Third Quarter	$ 69.41	$ 17.46
Fourth Quarter	$ 19.54	$ 4.85

On February 20, 2009, the closing sales price for our common stock was $6.44.

On February 20, 2009, there were 263 record holders of our common stock.

We have neither declared nor paid any cash dividends, 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, 2008, the following shares of common stock were withheld in satisfaction of tax withholding obligations arising from the vesting of restricted stock:

	Total Number of Shares Purchased	Maximum Number of Shares that May

Period	Total Number of Shares Purchased		Average Price Paid per Share	as Part of Publicly Announced Plans or Programs	Yet Be Purchased Under the Plans or Programs
October 1, 2008-October 31, 2008	47	$	10.70	N/A	N/A
November 1, 2008-November 30, 2008	1,341	$	10.09	N/A	N/A
December 1, 2008-December 31, 2008	283	$	8.19	N/A	N/A

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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 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,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues	$ 1,181,814	$ 677,452	$ 388,242	$ 287,693	$ 175,995
Expenses:					
Production	159,004	106,192	35,149	16,195	10,230
Production taxes	30,594	19,557	4,654	3,158	2,497
Drilling and services	26,186	44,211	98,436	52,122	26,442
Midstream and marketing	186,655	94,253	115,076	141,372	96,180
Depreciation, depletion and amortization natural gas and crude oil	290,917	173,568	26,321	9,313	4,909
Depreciation, depletion and amortization other	70,448	53,541	29,305	14,893	7,765
Impairment	1,867,497				
General and administrative	109,372	61,780	55,634	11,908	6,554
(Gain) loss on derivative contracts	(211,439)	(60,732)	(12,291)	4,132	878
(Gain) loss on sale of assets	(9,273)	(1,777)	(1,023)	547	(210)
Total operating expenses	2,519,961	490,593	351,261	253,640	155,245
(Loss) income from operations	(1,338,147)	186,859	36,981	34,053	20,750
Other income (expense):					
Interest income	3,569	4,694	991	206	56
Interest expense	(147,027)	(117,185)	(16,904)	(5,277)	(1,678)
Minority interest	(855)	276	(296)	(737)	(262)
Income (loss) from equity investments	1,398	4,372	967	(384)	(36)
Other income, net	1,454	729	118		
Total other income (expense)	(141,461)	(107,114)	(15,124)	(6,192)	(1,920)
(Loss) income before income taxes	(1,479,608)	79,745	21,857	27,861	18,830
Income tax (benefit) expense	(38,328)	29,524	6,236	9,968	6,433
(Loss) income from continuing operations	(1,441,280)	50,221	15,621	17,893	12,397
Income from discontinued operations, net of tax				229	451

Extraordinary gain(1)					12,544
Net (loss) income	(1,441,280)	50,221	15,621	18,122	25,392
Preferred stock dividends and accretion	16,232	39,888	3,967		
(Loss applicable) income available to common stockholders	$ (1,457,512)	$ 10,333	$ 11,654	$ 18,122	$ 25,392

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	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Earnings Per Share Information:					
Basic and Diluted					
(Loss) income from continuing operations	$ (9.26)	$ 0.46	$ 0.21	$ 0.31	$ 0.22
Income from discontinued operations, net of income tax				0.01	0.01
Extraordinary gain on acquisition					0.22
Preferred stock dividends	(0.10)	(0.37)	(0.05)		
(Loss) income per share (applicable) available to common stockholders	$ (9.36)	$ 0.09	$ 0.16	$ 0.32	$ 0.45
Weighted average number of common shares outstanding(2):					
Basic	155,619	108,828	73,727	56,559	56,312
Diluted	155,619	110,041	74,664	56,737	56,312

(1) We recognized an extraordinary gain from the recognition of the excess of fair value over acquisition cost of $12.5 million related to an acquisition we made in 2004.

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

	As of December 31,				
	2008	2007	2006	2005	2004
	(In thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$ 636	$ 63,135	$ 38,948	$ 45,731	$ 12,973
Property, plant and equipment, net	$ 3,175,559	$ 3,337,410	$ 2,134,718	$ 337,881	$ 114,818
Total assets	$ 3,655,058	$ 3,630,566	$ 2,388,384	$ 458,683	$ 197,017
Long-term debt	$ 2,375,316	$ 1,067,649	$ 1,066,831	$ 43,133	$ 59,340
Redeemable convertible preferred stock(1)	$	$ 450,715	$ 439,643	$	$
Total stockholders equity	$ 793,521	$ 1,766,891	$ 649,818	$ 289,002	$ 59,330
Total liabilities and stockholders equity	$ 3,655,058	$ 3,630,566	$ 2,388,384	$ 458,683	$ 197,017

(1) On May 7, 2008, we converted all of our then outstanding redeemable convertible preferred stock into shares of 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 crude 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 crude oil company concentrating on exploration, development and production activities. We are focused on continuing the exploration and exploitation of our significant holdings in the West Texas Overthrust, which we refer to as the WTO, a natural gas prone geological region where we have operated since 1986. The WTO includes the Piñon Field as well as the Allison Ranch, South Sabino, Big Canyon and McKay Creek exploration areas. We also operate interests in the Cotton Valley Trend in East Texas, the Gulf Coast area, the Mid-Continent and the Gulf of Mexico.

On November 21, 2006, we acquired all of the outstanding membership interests in NEG for total consideration of approximately $1.5 billion, excluding cash acquired. With core assets in the Val Verde and Permian Basins of West Texas, including overlapping or contiguous interests in the WTO, the NEG acquisition dramatically increased our exploration and production segment operations. In addition to the NEG acquisition, we have completed numerous acquisitions of additional working interests in the WTO during the period from late 2005 through 2008.

We currently generate the majority of our revenues, earnings and cash flow from the production and sale of natural gas and crude oil. Our revenues, profitability and future growth depend substantially on prevailing prices for natural gas and crude oil and on our ability to find and economically develop and produce natural gas and crude oil reserves. Prices for natural gas and crude 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 crude 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 net income largely is determined by the amount of work each performs for third parties. Revenues and costs related to work performed by our businesses for our own account are eliminated in consolidation and, therefore, do not contribute to our consolidated net income. Our ownership and control of these businesses, however, provide us with operational flexibility and an advantageous cost structure.

Recent Developments

During the second half of 2008, unprecedented levels of volatility in the financial and commodity markets made it necessary for us to reduce and refocus our exploration and development activities, reduce our budget for capital expenditures, explore the potential sale of certain assets and seek additional capital.

Private Placement of Convertible Perpetual Preferred Stock. In January 2009, we commenced and completed a private placement of 2,650,000 shares of a new series of 8.5% convertible perpetual preferred stock to qualified institutional buyers eligible under Rule 144A under the Securities Act. Net proceeds from the offering were approximately $243.9 million after deducting offering expenses of approximately $8.0 million. We used the net proceeds of the offering to repay outstanding borrowings under our senior credit facility and for general corporate purposes.

Each share of the convertible perpetual preferred stock has a liquidation preference of $100 and is entitled to an annual dividend of $8.50 payable semi-annually in cash, common stock or any combination thereof, beginning on February 15, 2010. No dividends will accrue or accumulate prior to August 15, 2009. Additionally, each share is initially convertible into 12.48 shares of our common stock, at the holder s option, at any time on or after April 15, 2009 based on an initial conversion price of $8.01 and subject to customary adjustments in certain circumstances.

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Marketing of Midstream Assets. In January 2009, we announced our intent to offer for sale certain of our gas gathering and related assets located in the WTO. This process is ongoing as of the date of this filing.

2009 Capital Expenditure Budget. We are introducing a 2009 production guidance range of 110.0 Bcfe to 120.0 Bcfe based on a capital expenditure guidance range of $500.0 million to $700.0 million. Based on the current and anticipated near-term drilling activity and associated expenditures, it is currently expected that full year results will trend toward the lower half of these ranges.

Drilling Activity. We began to decrease the number of rigs running on our properties during December 2008 in preparation for reduced 2009 activity levels. At February 20, 2009, we had 9 rigs running compared to a high of 47 rigs operating in the second quarter of 2008.

East Texas/North Louisiana Haynesville Shale Play: We control approximately 36,000 acres in the developing Haynesville shale play of East Texas and North Louisiana. We drilled two vertical test wells within the Oakhill field area in Rusk County to evaluate the potential for Haynesville shale production. The initial well had a total of 260 feet of Haynesville shale thickness and tested at a rate of 1.5 MMcfe per day. The second well encountered 288 feet of shale thickness and is awaiting completion.

Segment Overview

We operate in four related business segments: exploration and production, drilling and oil field services, midstream gas services and other ancillary business activities. Management evaluates the performance of our business segments based on operating income, which is computed as segment operating revenues less operating expenses and depreciation, depletion, amortization and impairment. 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.

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Segment revenues:			
Exploration and production	$ 912,496	$ 478,747	$ 106,413
Drilling and oil field services	46,991	73,202	138,657
Midstream gas services	204,138	107,578	122,892
Other	18,189	17,925	20,280
Total revenues	1,181,814	677,452	388,242
Segment operating (loss) income:			
Exploration and production	(1,263,249)	198,913	17,069
Drilling and oil field services	(5,393)	10,473	32,946
Midstream gas services	2,087	6,783	3,528
Other	(71,592)	(29,310)	(16,562)
Total operating (loss) income	(1,338,147)	186,859	36,981
Interest income	3,569	4,694	991
Interest expense	(147,027)	(117,185)	(16,904)
Other income (expense)	1,997	5,377	789
(Loss) income before income taxes	$ (1,479,608)	$ 79,745	$ 21,857
Production data:			
Natural gas (MMcf)	87,402	51,958	13,410
Crude oil (MBbls)	2,334	2,042	322
Combined equivalent volumes (MMcfe)	101,405	64,211	15,342
Average daily combined equivalent volumes (MMcfe/d)	277.1	175.9	42.0
Average prices- as reported(1):			
Natural gas (per Mcf)	$ 7.95	$ 6.51	$ 6.19
Crude oil (per Bbl)(2)	$ 91.54	$ 68.12	$ 56.61
Combined equivalent (per Mcfe)	$ 8.96	$ 7.45	$ 6.60
Average prices- including impact of derivative contract settlements:			
Natural gas (per Mcf)	$ 7.90	$ 7.18	$ 7.25
Crude oil (per Bbl)(2)	$ 88.09	$ 68.10	$ 56.61
Combined equivalent (per Mcfe)	$ 8.83	$ 7.98	$ 7.52
Drilling and oil field services:			
Number of operational drilling rigs owned at end of period	28	25	25
Average number of operational drilling rigs owned during the period	27.6	26.0	21.9

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

(2) Includes natural gas liquids.

Exploration and Production Segment

We explore for, develop and produce natural gas and crude oil reserves, with a focus on our proved reserves and extensive undeveloped acreage positions in the WTO. We operate substantially all of our wells in our core areas and employ our drilling rigs and other drilling services in the exploration and development of our operated wells and, to a lesser extent, of our non-operated wells.

The primary factors affecting the financial results of our exploration and production segment are the prices we receive for our natural gas and crude oil production, the quantity of our natural gas and crude oil production 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 crude oil production. Because we are vertically integrated, our exploration and production activities affect the results of our drilling and oil field services and midstream gas services segments, especially in times of weak demand for natural gas and crude oil. Our acquisition of NEG in November 2006 substantially increased our revenues and operating income in our exploration and production segment. As additional acquisitions have further increased our working interest in the WTO, a larger percentage of the work performed by our services segments has been performed for our own account.

As of December 31, 2008, we had 2,158.6 Bcfe of estimated net proved reserves with a PV-10 of $2,258.5 million, which is an increase from 1,516.2 Bcfe of estimated net proved reserves with a PV-10 of $3,550.5 million as of December 31, 2007. Our Standardized Measure of Discounted Future Net Cash Flows was $2,220.6 million at December 31, 2008 as compared to $2,718.5 million at December 31, 2007 and $1,440.2 million at December 31, 2006. For a discussion of PV-10 and reconciliation to Standardized Measure of Discounted Net Cash Flows, see Business Our Business and Primary Operations Proved Reserves in Item 1 of this report. The decrease in PV-10 in 2008 was primarily attributable to lower commodity prices at December 31, 2008 compared to December 31, 2007. 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 reporting period. Under SEC guidelines, natural gas and crude oil reserves are calculated based on posted prices on the last day of the reporting period with consideration of price changes only to the extent provided by contractual arrangements. As of December 31, 2008, these prices were $5.71 per Mcf of natural gas and $44.60 per barrel of oil. While the overall estimated reserve quantities assigned to our properties increased from December 31, 2007 to December 31, 2008, prices used to determine the future value of our reserves declined to such an extent as to necessitate a ceiling impairment of $1,855.0 million.

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

Exploration and production segment revenues increased to $912.5 million in the year ended December 31, 2008 from $478.7 million in 2007, an increase of 90.6%, as a result of a 57.9% increase in combined production volumes and a 20.3% increase in the average price we received for the natural gas and crude oil we produced. During 2008, we increased natural gas production by 35.4 Bcf to 87.4 Bcf and increased crude oil production by 292 MBbls to 2,334 MBbls. The total combined 37.2 Bcfe increase in production was due primarily to successful drilling in the WTO and an increase in our average working interest in the WTO (96.2% at December 31, 2008 from 93.0% at December 31, 2007). We owned interests in a total of 2,059 producing wells at December 31, 2008 compared to 1,654 producing wells at December 31, 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 crude 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 crude oil production was negatively impacted by the significant decline in natural gas and crude oil prices experienced by the oil and gas industry in the fourth quarter of 2008. The average price received for our natural gas and crude 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 crude 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 crude oil derivative contract settlements decreased our effective price received for crude 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 crude oil, which was $68.10. 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 crude oil production to determine effective prices. As of December 31, 2008, we had natural gas and crude oil derivative

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contracts, excluding basis swaps, of 79.8 Bcfe at an average price of $8.60 per Mcfe in place for 2009 and 68.4 Bcfe at an average price of $7.77 per Mcfe in place for 2010. The Company also had natural gas basis swaps in place through 2011 for 125.9 Bcf at an average price of $0.73 per Mcf.

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 $433.7 million increase in exploration and production segment revenues and $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, depletion and amortization (DD&A) on natural gas and crude oil properties due to the increase in production. The full cost ceiling impairment was the result of the decline of the future value of our reserves due to the natural gas and crude oil prices at December 31, 2008 which offset the increase in overall estimated reserve quantities assigned to our properties. Natural gas and crude oil prices were $5.71 per Mcf and $44.60 per Bbl at December 31, 2008 compared to $6.80 per Mcf and $95.98 per Bbl at December 31, 2007. The increase in production expenses was attributable to the increase in the number of operating wells we own and the increase in our average working interests in those wells. DD&A increased due to an increase in our depreciable properties, higher future development costs and increased production.

During 2007 and 2008, we entered into natural gas and crude oil swaps and natural gas basis swaps. Given the long-term nature of our investment in the WTO development program, we believe it prudent to enter into natural gas and crude oil swaps and natural gas basis swaps for a portion of our production in order to stabilize future cash inflows for planning purposes. 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 crude oil derivative contracts recorded during the year ended December 31, 2008 was attributable to a decrease in average natural gas and crude oil prices at December 31, 2008 compared to the average natural gas and crude oil prices at December 31, 2007 or the contract price for contracts entered into during 2008.

Exploration and Production Segment   Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

For the year ended December 31, 2007, exploration and production segment revenues increased to $478.7 million from $106.4 million in 2006. The increase in 2007 revenues compared to 2006 was attributable to increased production primarily due to acquisitions and successful drilling activity. Production volumes increased to 64.2 Bcfe in 2007 from 15.3 Bcfe in 2006, representing an increase of 48.9 Bcfe, or 318.5%. Average combined prices increased $0.85, or 12.9%, to $7.45 per Mcfe in 2007 compared to $6.60 per Mcfe in 2006.

Exploration and production segment operating income increased $181.8 million in 2007 to $198.9 million from $17.1 million in 2006. The $372.4 million increase in exploration and production segment revenues was partially offset by a $71.0 million increase in production expenses and a $147.2 million increase in DD&A. The increase in production expenses was attributable to the additional properties acquired in the NEG acquisition and operating expenses on our new wells. During the year ended December 31, 2007, the exploration and production segment reported a $60.7 million gain on our derivative positions ($34.5 million realized gain and $26.2 million unrealized gain) compared to a $12.3 million net gain ($14.2 million realized gain and $1.9 million unrealized loss) in 2006.

Drilling and Oil Field Services Segment

We drill for our own account primarily in the WTO through our drilling and oil field services subsidiary, Lariat. We also drill wells for other natural gas and crude oil companies, primarily located in the West Texas region. As of

December 31, 2008, our drilling rig fleet consisted of 39 operational rigs, 28 of which we owned directly and 11 of which were owned by Larclay. Our oil field services business conducts operations that complement our drilling

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services operation. These services include providing pulling units, trucking, rental tools, location and road construction and roustabout services to us and our subsidiaries as well as to third parties.

In 2006, Lariat and its partner, Clayton Williams Energy, Inc. (CWEI), formed a limited partnership, Larclay, in which we and CWEI each have a 50% interest. Larclay acquired twelve sets of rig components and other related equipment to assemble into completed land drilling rigs. The drilling rigs were to be used for drilling on CWEI s prospects or our prospects or for contracting to third parties on daywork drilling contracts. All but one of these rigs have been assembled. Larclay financed the acquisition cost of the rigs with a loan from a third party, secured by the purchased rigs, and a loan from CWEI. In addition, CWEI has guaranteed a portion of the third party debt. Lariat operates the rigs owned by the partnership. If Larclay has an operating shortfall, Lariat and CWEI are obligated to provide loans to the partnership. In April 2008, Lariat and CWEI each made loans of $2.5 million to Larclay under promissory notes. The notes bear interest at a floating rate based on a London Interbank Offered Rate (LIBOR) average plus 3.25% (5.1875% at December 31, 2008) as provided in the Larclay partnership agreement. In June 2008, Larclay executed a $15.0 million revolving promissory note with each of Lariat and CWEI. Amounts drawn under each revolving promissory note bear interest at a floating rate based on a LIBOR average plus 3.25% (5.1875% at December 31, 2008) as provided in the Larclay partnership agreement. Lariat and CWEI each advanced $5.0 million to Larclay under the revolving promissory notes during the year ended December 31, 2008. The cash shortfalls that Larclay experienced in 2008 resulted from principal payments due pursuant to its rig loan agreement. As a result of current economic conditions and continued cash shortfalls for Larclay, we have fully impaired both our investment in and notes receivable due from Larclay, resulting in impairment expense of approximately $12.5 million, as of December 31, 2008.

Although Lariat s 50% interest in Larclay affords us access to Larclay s eleven operational rigs, we do not control Larclay. We account for our investment in Larclay under the equity method of accounting, and, therefore, do 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. The financial results of our drilling and oil field services segment depend on many factors, particularly the demand for and the price we can charge for our services. We provide drilling services for our account and for others, generally on a daywork, and less often on a turnkey, contract basis. We generally assess the complexity and risks of operations, the on-site drilling conditions, the type of equipment to be used, the anticipated duration of the work to be performed and the prevailing market rates in determining the contract terms we offer.

Daywork Contracts. Under a daywork drilling contract, we provide a drilling rig with required personnel to our customer who supervises the drilling of the well. We are paid based on a negotiated fixed rate per day while the rig is in use. Daywork drilling contracts specify the equipment to be used, the size of the hole and the depth of the well. Under a daywork drilling contract, the customer bears a large portion of the out-of-pocket drilling costs, and we generally bear no part of the usual risks associated with drilling, such as time delays and unanticipated costs. As of December 31, 2008, sixteen of our directly owned rigs were operating under daywork contracts and thirteen of these were working for our account.

Turnkey Contracts. Under a typical turnkey contract, a customer pays us to drill a well to a specified depth and under specified conditions for a fixed price, regardless of the time required or the problems encountered in drilling the well. We provide most of the equipment and drilling supplies required to drill the well. We subcontract for related services such as the provision of casing crews, cementing and well logging. Generally, we do not receive progress payments and are paid only after the well is drilled. As of December 31, 2008, none of our rigs was operating under a turnkey contract.

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

Drilling and oil field services segment revenues decreased to $47.0 million for the year ended December 31, 2008 from $73.2 million for the year ended December 31, 2007 resulting in an operating loss of $5.4 million during 2008 compared to operating income of $10.5 million during 2007. Our drilling and oil field services segment records revenues and operating income only on wells drilled for or on behalf of third parties. The portion of drilling costs incurred by our drilling and oil field services segment relating to our ownership interest is capitalized as part of our full cost pool. The decline in revenues 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 crude 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 2008, an average of 24.6 of the 27.6 operational rigs we owned were working for our account compared to an average of 20.0 of the 26.0 operational rigs working for our account during 2007. As a result, 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% during 2007. Additionally, the average daily rate 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. During the year ended December 31, 2007, two of our rigs working for third parties operated under turnkey contracts, while none of our rigs operated under turnkey contracts during the year ended December 31, 2008. Additionally, the daywork and turnkey contracts in place for 2007 generated higher per day revenue due to higher rates in place for those contracts. The operating loss of $5.4 million in 2008 is attributed to the $12.5 million impairment on the investment in and notes receivable due from Larclay.

Drilling and Oil Field Services Segment Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

During 2007, our drilling and oil field services segment reported $73.2 million in revenues, a decrease of $65.5 million, or 47.2%, from 2006. Operating income decreased to $10.5 million in 2007 from $32.9 million in 2006. The decline in revenues and operating income is primarily attributable to an increase in the number of rigs operating on our properties and an increase in our ownership interest in our natural gas and crude oil properties. With the NEG acquisition and other WTO property acquisitions during 2007, our average working interest increased to approximately 93% in the wells we operated in the WTO. During the year ended December 31, 2007, 72.0% of drilling and oil field service segment revenues were generated by work performed on our own account and eliminated in consolidation compared to 34.3% in 2006.

Midstream Gas Services Segment

We provide gathering, compression, processing and treating services of natural gas in West Texas, primarily through our wholly owned subsidiary, SandRidge Energy Midstream, Inc. (formerly known as ROC Gas Company, Inc.). Through our gas marketing subsidiary, Integra Energy, we buy and sell natural gas produced from our operated wells as well as third-party operated wells. Gas marketing revenue is one of our largest revenue components; however, gas marketing is a very low-margin business. Substantially all of our marketing fees are billed on a per unit basis. On a consolidated basis, gas purchases and other costs of sales include the total value we receive from third parties for the natural gas we sell and the amount we pay for natural gas, which are reported as midstream and marketing expense. The primary factors affecting our midstream gas services are the quantity of natural gas we gather, treat and market and the prices we pay and receive for natural gas.

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

Midstream gas services segment revenues for the year ended December 31, 2008 was $204.1 million compared to $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.

Midstream Gas Services Segment Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Midstream gas services segment revenues decreased $15.3 million to $107.6 million for the year ended December 31, 2007 from $122.9 million in 2006. The decrease in midstream gas services revenues is attributable to the increase in our working interest in the WTO as a result of the NEG and other acquisitions. Operating income increased to $6.8 million in 2007 from $3.5 million in 2006 primarily due to lower gas prices paid.

Other Segment

Our other segment consists primarily of our CO_2 gathering and sales operations and corporate operations. We conduct our CO_2 gathering and sales operations through our wholly owned subsidiary, SandRidge CO_2, LLC (formerly operated through PetroSource Energy Company, LLC). SandRidge CO_2 gathers CO_2 from natural gas treatment plants located in West Texas and transports and sells this CO_2 for use in tertiary crude oil recovery operations conducted by us and third parties.

The operating loss in the other segment was $71.6 million for 2008 compared to $29.3 million for 2007 and $16.6 million for 2006. The increases in operating losses from 2006 through 2008 are primarily attributable to increases in corporate and support staff necessary to accommodate the growth in our exploration and development programs and our production levels during that time.

Results of Operations

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 crude oil sales and $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	2007	$ Change	% Change
		(In thousands)		
Revenues:				
Natural gas and crude 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 crude 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 crude 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 crude 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 crude 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 crude oil production was negatively impacted by the significant decline in natural gas and crude 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 crude 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 is 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, depletion, and amortization natural gas and crude 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 contracts	(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 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 $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. The effect on production taxes of the increased prices received for our production was offset by an increase in production tax exemptions realized during 2008 compared to 2007. As a result, production taxes on a unit-of-production basis remained constant at $0.30 per Mcfe for 2008 and 2007.

Drilling and services expenses, which includes operating expenses of the drilling, oil field services and CO_2 services companies, decreased $18.0 million, or 40.8%, to $26.2 million in 2008 compared to $44.2 million in 2007, primarily because of the increase in the number and working interest ownership of the wells we drilled for our own account, which resulted in 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.

DD&A for our natural gas and crude oil properties increased to $290.9 million during 2008 from $173.6 million in 2007. Our DD&A per Mcfe increased $0.17 to $2.87 from $2.70 in 2007. The increase is primarily attributable to the increase in our depreciable properties, higher future development costs and increased production. Our production increased 57.9% to 101.4 Bcfe in 2008 from 64.2 Bcfe in 2007.

DD&A for our other assets consists primarily of depreciation of our drilling rigs, midstream gathering and compression facilities and other equipment. 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. 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. Our drilling rigs and related oil field services equipment are depreciated over an average seven-year useful life.

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 crude oil properties exceeded our full cost ceiling limitation. There was no full cost ceiling impairment as of December 31, 2007. The additional impairment expenses 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 is 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 $14.5 million for 2008 and $4.6 million for 2007. 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.

Due to the decline in average natural gas and crude oil prices during the second half of 2008, we recorded a gain of $211.4 million ($224.4 million unrealized gain and $13.0 million realized loss) on our derivatives contracts for 2008 compared to a $60.7 million gain ($26.2 million unrealized gain and $34.5 million realized 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 net other expense increased to $141.5 million for the year ended December 31, 2008 from $107.1 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%
Minority interest	(855)	276	(1,131)	(409.8)%
Income from equity investments	1,398	4,372	(2,974)	(68.0)%
Other income, net	1,454	729	725	99.5%
Total other income (expense), net	(141,461)	(107,114)	(34,347)	32.1%
(Loss) income before income taxes	(1,479,608)	79,745	(1,559,353)	(1,955.4)%
Income tax (benefit) expense	(38,328)	29,524	(67,852)	(229.8)%

Net (loss) income	$ (1,441,280)	$ 50,221	$ (1,491,501)	(2,969.9)%

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 Grey Ranch, L.P.

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 of $1,479.6 million 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 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.

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

Impact of the NEG Acquisition. The results of operations for the year ended December 31, 2006 include the results of NEG from November 21, 2006. The results of operations for the year ended December 31, 2007 include the NEG acquisition for the full year. Although NEG was principally an exploration and production company, the acquisition affected several of our revenue and expense categories. Revenues and expenses related to our natural gas and crude oil operations increased due to increased production from the acquired NEG properties. Revenues and expenses relating to our drilling and services and midstream and marketing operations decreased due to increased intercompany eliminations as more services were provided on company-owned properties. General and administrative expenses increased due to the addition of new staff. Interest expense increased due to the additional borrowings incurred in conjunction with the NEG acquisition.

Revenues. Total revenues increased 75% to $677.5 million for the year ended December 31, 2007 from $388.2 million in 2006. This increase was due to a $376.4 million increase in natural gas and crude oil sales and was partially offset by lower revenues in our other segments.

	Year Ended December 31,			
	2007	2006	$ Change	% Change
	(In thousands)			
Revenues:				
Natural gas and crude oil	$ 477,612	$ 101,252	$ 376,360	371.7%
Drilling and services	73,197	139,049	(65,852)	(47.4)%
Midstream and marketing	107,765	122,896	(15,131)	(12.3)%
Other	18,878	25,045	(6,167)	(24.6)%
Total revenues	$ 677,452	$ 388,242	$ 289,210	74.5%

Total natural gas and crude oil revenues increased $376.4 million to $477.6 million for the year ended December 31, 2007, compared to $101.3 million in 2006, primarily as a result of an increase in natural gas and crude oil production volumes. Total natural gas production increased 287% to 52.0 Bcf in 2007 compared to 13.4 Bcf in 2006, while crude oil production increased 534% to 2,042 MBbls in 2007 from 322 MBbls in 2006. The increase was due to the NEG acquisition and our successful drilling in the WTO. The average price received for our natural gas and crude oil production increased 13% in 2007 to $7.45 per Mcfe compared to $6.60 per Mcfe in 2006, excluding the impact of derivative contracts.

Drilling and services revenues decreased 47% to $73.2 million in 2007 compared to $139.0 million in 2006. The decline in revenues is primarily attributable to an increase in the number of our rigs operating on our properties and an increase in our ownership interest in our natural gas and crude oil properties.

Midstream and marketing revenues decreased $15.1 million, or 12%, with revenues of $107.8 million for the year ended December 31, 2007, compared to $122.9 million in 2006. The NEG acquisition significantly decreased our midstream gas services revenues as more gas was transported for our own account. Prior to the acquisition, transportation, treating and processing of gas for NEG was recorded as midstream gas services revenues.

Other revenue decreased to $18.9 million during 2007 from $25.0 million in 2006. The decrease was primarily due to the sale of various non-energy related assets to our former President and Chief Operating Officer. Revenues related to these assets are included in the 2006 period prior to their sale in August 2006. This decrease was slightly offset by an increase in revenues generated by our CO_2 operations.

Operating Costs and Expenses. Total operating costs and expenses increased to $490.6 million in 2007, compared to $351.3 million in 2006, primarily due to increases in our production-related costs as well as an increase in corporate staff. These increases were partially offset by decreases in costs attributable to our drilling and services and midstream and marketing operations as well as increased gains on derivative instruments.

	Year Ended December 31, 2007	2006	$ Change	% Change
		(In thousands)		
Operating costs and expenses:				
Production	$ 106,192	$ 35,149	$ 71,043	202.1%
Production taxes	19,557	4,654	14,903	320.2%
Drilling and services	44,211	98,436	(54,225)	(55.1)%
Midstream and marketing	94,253	115,076	(20,823)	(18.1)%
Depreciation, depletion, and amortization natural gas and crude oil	173,568	26,321	147,247	559.4%
Depreciation, depletion and amortization other	53,541	29,305	24,236	82.7%
General and administrative	61,780	55,634	6,146	11.0%
Gain on derivative instruments	(60,732)	(12,291)	(48,441)	(394.1)%
Gain on sale of assets	(1,777)	(1,023)	(754)	(73.7)%
Total operating costs and expenses	$ 490,593	$ 351,261	$ 139,332	39.7%

Production expenses increased $71.0 million due to increased production from our 2007 drilling activity and the addition of the NEG properties. The remainder of the increase was due to an increase in lease operating expenses due to an increase in the number of wells we operate. Production taxes increased $14.9 million, or 320%, to $19.6 million primarily due to increased natural gas production as a result of our 2007 drilling activity and the addition of the NEG properties in 2006.

Drilling and services and midstream and marketing expenses decreased 55% and 18% respectively, during 2007 compared to 2006 primarily because of the increase in the number and working interest ownership of the wells we drilled for our own account.

DD&A for our natural gas and crude oil properties increased to $173.6 million during 2007 from $26.3 million in 2006. Our DD&A per Mcfe increased $0.98 to $2.70 from $1.72 in 2006. The increase is primarily attributable to our 2007 capital expenditures and the NEG acquisition, which increased our depreciable properties by the purchase price plus future development costs and also increased production. Our production increased 320% to 64.2 Bcfe from 15.3 Bcfe in 2006.

The $24.2 million increase in DD&A for our other assets was due primarily to our increased investments in rigs, other oilfield services equipment and midstream assets. During 2006 and 2007, capital expenditures for drilling rigs, other oilfield services equipment and midstream assets totaled approximately $293.0 million.

General and administrative expenses increased 11% to $61.8 million in 2007 from $55.6 million in 2006. The increase was principally attributable to a $17.3 million increase in corporate salaries and wages due to a significant increase in corporate and support staff. As of December 31, 2007, we had 2,227 employees compared to 1,443 at December 31, 2006. The increase in corporate salaries and wages was partially offset by $4.6 million in capitalized general and administrative expenses, a $5.5 million decrease due to a legal settlement recorded in 2006 and a

$1.6 million decrease in stock compensation expense. During 2006 we settled a legal dispute resulting in an additional loss on the settlement of $5.5 million. As part of a severance package for certain executive officers, the Board of Directors approved the acceleration of vesting of certain stock awards resulting in increased compensation expense recognized during 2006. There were no general and administrative expenses capitalized in 2006.

For the year ended December 31, 2007, we recorded a gain of $60.7 million ($26.2 million unrealized gain and $34.5 million realized gain) on our derivative contracts compared to a $12.3 million gain ($1.9 million unrealized loss and $14.2 million realized gain) in 2006. The unrealized gain recorded during 2007 was attributable to a decrease in average natural gas prices at December 31, 2007 as compared to the average natural gas prices at December 31, 2006 or the various contract dates for contracts entered into during 2007.

Other Income (Expense). Total net other expense increased to $107.1 million for the year ended December 31, 2007 from $15.1 million in 2006. The increase is reflected in the table below.

	Year Ended December 31, 2007	2006	$ Change	% Change
	(In thousands)			
Other income (expense):				
Interest income	$ 4,694	$ 991	$ 3,703	373.7%
Interest expense	(117,185)	(16,904)	(100,281)	593.2%
Minority interest	276	(296)	572	193.2%
Income from equity investments	4,372	967	3,405	352.1%
Other income, net	729	118	611	517.8%
Total other expense, net	(107,114)	(15,124)	(91,990)	(608.2)%
Income before income taxes	79,745	21,857	57,888	264.8%
Income tax expense	29,524	6,236	23,288	373.4%
Net income	$ 50,221	$ 15,621	$ 34,600	221.5%

Interest income increased to $4.7 million in 2007 from $1.0 million in 2006. This increase was due to interest income from investment of excess cash after the repayment of debt.

Interest expense increased to $117.2 million during 2007 from $16.9 million in 2006. This increase was attributable to increased average debt balances. To finance the NEG acquisition, we entered into a $750 million senior credit facility, which had an initial borrowing base of $300 million, and an $850 million senior bridge facility. In March 2007, we repaid the senior bridge facility and expensed the related unamortized debt issuance costs of $12.5 million, which resulted in higher interest expense.

During the year ended December 31, 2007 we reported income from equity investments of $4.4 million compared to $1.0 million in 2006. Approximately $1.9 million of the increase was attributable to income from our interest in the Grey Ranch treating plant, which experienced increased profitability due to higher levels of utilization in 2007 compared to 2006. Approximately $1.5 million of the increase was attributable to income from Larclay as all of Larclay s rigs had been delivered and all but one rig was operational by December 31, 2007.

We reported income tax expense of $29.5 million for the year ended December 31, 2007 compared to $6.2 million in 2006. The 2007 income tax expense represented an effective income tax rate of 37.0% compared to 28.5% in 2006. The lower effective income tax rate in 2006 was attributable to favorable percentage depletion deductions during that period.

Liquidity and Capital Resources

Summary

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

Debt and equity capital markets experienced adverse conditions during the latter part of 2008. 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 Commodity Services, Inc. (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.

Our senior credit facility limits the amounts we can borrow to a borrowing base amount, currently $1.1 billion. 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. Our ability to develop properties and changes in commodity prices may affect the borrowing base of our senior credit facility.

On November 9, 2007, we completed the initial public offering of our common stock. We sold 32,379,500 shares of our common stock, including 4,170,000 shares sold directly to an entity controlled by our Chief Executive Officer and President. After deducting underwriting discounts of approximately $44.0 million and offering expenses of approximately $3.1 million, we received net proceeds of approximately $794.7 million. The net proceeds were utilized 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 capital expenditures	229.7
Total	$ 794.7

In May 2008, we privately placed $750.0 million of our 8.0% Senior Notes due 2018. We used $478.0 million of the $735.0 million net proceeds received from the offering to repay the total balance outstanding on our senior credit facility. The remaining proceeds were used to fund a portion of our capital expenditures for 2008.

As of December 31, 2008, our cash and cash equivalents were $0.6 million, and we had approximately $494.0 million available to be drawn, excluding amounts to be funded by Lehman Brothers, under our senior credit facility based on a borrowing base of $1.1 billion. Amounts outstanding under our senior credit facility at December 31, 2008 totaled $573.5 million. As of December 31, 2008, we had approximately $2.4 billion in total debt outstanding. As of February 20, 2009, the balance outstanding under our senior credit facility was $565.3 million, and $502.2 million was available to be drawn under our senior credit facility after consideration of our $24.5 million in outstanding letters of credit and excluding amounts to be funded by Lehman Brothers.

In January 2009, we completed a private placement of 2,650,000 shares of 8.5% convertible perpetual preferred stock to qualified institutional buyers eligible under Rule 144A under the Securities Act. The placement included 400,000 shares of convertible perpetual preferred stock issued upon the full exercise of the initial purchasers option to cover over-allotments. Net proceeds from the offering were approximately $243.9 million after deducting offering expenses of approximately $8.0 million. We used the net proceeds of the offering to repay outstanding borrowings under our senior credit facility and for general corporate purposes.

Based upon the current level of operations and anticipated growth, we believe our cash flows from operations, current cash and investments on hand, availability under our senior credit facility, proceeds from our private offering of 8.5% convertible perpetual preferred stock and anticipated proceeds from the sale of our midstream assets located in the Piñon Field, 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.

Capital Expenditures

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 crude oil reserves.

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

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Capital Expenditures:			
Exploration and production	$ 1,909,078	$ 1,046,552	$ 170,872
Drilling and oil field services	52,869	123,232	89,810
Midstream gas services	160,460	63,828	16,975
Other	55,440	47,236	28,884
Capital expenditures, excluding acquisitions	2,177,847	1,280,848	306,541
Acquisitions		116,650	1,054,075
Total	$ 2,177,847	$ 1,397,498	$ 1,360,616

For 2009, we have budgeted a range of $500.0 million to $700.0 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.

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 exceeds our cash flows from operations and we generally use excess cash, when available, to pay down borrowings outstanding under our credit arrangements.

We maintain access to funds that may be needed to meet capital requirements through our senior credit facility. As of December 31, 2008, we had approximately $494.0 million available to be drawn under our senior credit facility, excluding amounts to be funded by Lehman Brothers. At December 31, 2008, we had a working capital deficit of $46.7 million compared to a deficit of $5.7 million at December 31, 2007. Current assets increased $129.5 million at December 31, 2008, compared to current assets at December 31, 2007, primarily due to a $179.2 million increase in our current derivative contract assets resulting from the decline in natural gas and crude oil market prices compared to the contract prices. Current liabilities increased $170.5 million primarily as a result of an increase of $150.7 million in accounts payable.

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Cash Flows

Our cash flows are as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Cash Flows:			
Cash flows provided by operating activities	$ 579,189	$ 357,452	$ 67,349
Cash flows used in investing activities	(1,909,443)	(1,385,581)	(1,340,567)
Cash flows provided by financing activities	1,267,755	1,052,316	1,266,435
Net (decrease) increase in cash and cash equivalents	$ (62,499)	$ 24,187	$ (6,783)

Operating Activities. Net cash provided by operating activities for the years ended December 31, 2008 and 2007 were $579.2 million and $357.5 million, respectively. The increase in cash provided by operating activities from 2007 to 2008 was 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 provided by operating activities increased $290.1 million to $357.5 million in 2007 from $67.3 million in 2006 primarily due to our $34.6 million increase in net income as a result of our approximately 320% increase in production volumes related to the NEG and various other acquisitions as well as our drilling success. Also, contributing to this increase was $34.5 million in realized gains on our derivative contracts. These increases were partially offset by increases in general and administrative costs such as salaries and wages.

Investing Activities. 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.

Cash flows used in investing activities increased to $1,385.6 million during 2007 from $1,340.6 million in 2006. During 2006, we acquired NEG for $990.4 million, net of cash received and $231.2 million in common stock. Capital expenditures for property, plant and equipment during 2007 were $1,280.8 million as compared to $306.5 million in 2006 as we expanded our capital expenditure program. During 2007, our capital expenditures were $1,046.6 million in our exploration and production segment, $123.2 million for drilling and oil field services, $63.8 million for midstream gas services and $47.2 million for other capital expenditures.

Financing Activities. Since December 2005, we have used equity issuances and borrowings to supplement our cash flows from operations to fund our growth. 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. 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.

During 2007, we raised $1,114.7 million in equity issuances and had net cash repayments of $0.7 million of debt. Our equity issuances included the November 2007 initial public offering of our common stock yielding net proceeds of $794.7 million and a March 2007 private placement of our common stock, which provided net proceeds of approximately $318.7 million. Proceeds from borrowings were $1,331.5 million during 2007 and we repaid approximately $1,332.2 million, leaving net cash repayments during 2007 of approximately $0.7 million. We used the net proceeds from our term loan and the common stock issuances to repay our senior bridge facility and all of the outstanding borrowings under our senior credit facility. Our financing activities provided $1,052.3 million in cash during 2007 compared to $1,266.4 million in 2006.

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Indebtedness

Senior Credit Facility. On November 21, 2006, we entered into a $750.0 million senior secured revolving credit facility with Bank of America, N.A., as administrative agent. The senior credit facility matures on November 21, 2011 and is available to be drawn on and repaid without restriction so long as we are in compliance with its terms, including certain financial covenants.

The senior credit facility bank group consists of 27 financial institutions. The largest commitment from any lender in the syndicate is 6.31% of the facility. The credit agreement for the facility contains various covenants that limit our ability, and the ability of 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 our ability and the ability of certain of our subsidiaries to incur additional indebtedness with certain exceptions, including under the senior notes (as discussed below).

On October 3, 2008, 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 do not anticipate that Lehman Brothers will 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.

The senior credit facility also contains financial covenants, including maintenance of agreed upon 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 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 calculated using the last four completed fiscal quarters, and (iii) current ratio, which must be at least 1.0:1.0. 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 our derivative contracts are disregarded. As of December 31, 2008, we were in compliance with all of the financial covenants under the senior credit facility.

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

At our election, interest under the senior credit facility is determined by reference to (i) LIBOR plus an applicable margin between 1.25% and 2.00% per annum or (ii) the higher of the federal funds rate plus 0.5% or the prime rate plus, in either case, an applicable margin between 0.25% and 1.00% 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 our senior credit facility for the year ended December 31, 2008 was 3.82%.

The borrowing base of the senior credit facility is subject to review semi-annually; however, the lenders reserve the right to have one additional redetermination of the borrowing base per calendar year. We also may request up to two unscheduled redeterminations per year. The borrowing base is determined based on proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. The borrowing base, as of

December 31, 2008, was $1.1 billion. As of December 31, 2008, we had total outstanding indebtedness of $573.5 million under our senior credit facility.

Other Indebtedness. We have financed a portion of our drilling rig fleet and related oil field services equipment through the issuance of notes secured by the equipment. At December 31, 2008, the aggregate outstanding balance of these notes was $33.0 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 $1.2 million. The notes have a prepayment penalty (currently ranging from 1% to 2%) that is triggered if we repay the notes prior to maturity.

On November 15, 2007, we entered into a $20.0 million note payable, which is fully secured by one of the buildings and a parking garage located on our property in downtown Oklahoma City, Oklahoma. We purchased the property in July 2007 to serve as our corporate headquarters. The mortgage bears interest at 6.08% per annum 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. We made payments of principal and interest on this note totaling $0.8 million and $1.2 million, respectively, during 2008.

We have financed the purchase of other equipment used in our business. At December 31, 2006, the aggregate outstanding balance on these financings was $4.5 million. We substantially repaid such borrowings during July 2007.

8.625% Senior Term Loan and Senior Floating Rate Term Loan. On March 22, 2007, we issued $1.0 billion principal amount of unsecured senior term loans. A portion of the proceeds of the senior term loans was used to repay the senior bridge facility described below under Senior Bridge Facility. The senior term loans included both a floating rate tranche and fixed rate tranche as described below.

The floating rate tranche consisted of a $350.0 million senior term loan at a variable rate with interest payable quarterly and principal due on April 1, 2014. The variable rate term loan bore interest, at our option, at LIBOR plus 3.625% or the higher of (i) the federal funds rate, as defined, plus 3.125% or (ii) a bank s prime rate plus 2.625%.

The fixed rate tranche consisted of a $650.0 million senior term loan at a fixed rate of 8.625% per annum with principal due on April 1, 2015. Under the terms of the fixed rate term loan, interest was payable quarterly and during the first four years interest could be paid, at our option, either entirely in cash or entirely with additional fixed rate term loans.

As discussed below, the senior term loans were exchanged pursuant to the senior term loan credit agreement.

8.625% Senior Notes Due 2015 and Senior Floating Rate Notes Due 2014. On May 1, 2008, we completed an offer to exchange the senior term loans for senior unsecured notes with registration rights, as required under the senior term loan credit agreement. We issued $650.0 million of 8.625% Senior Notes due 2015 in exchange for an equal outstanding principal amount of our fixed rate term loan and $350.0 million of Senior Floating Rate Notes due 2014 in exchange for an equal outstanding principal amount of our variable rate term loan. The newly issued senior notes had terms that were substantially identical to those of the exchanged senior term loans. During the third quarter of 2008, we filed a registration statement to enable holders of the notes to exchange them for substantially identical notes that are registered under the Securities Act. All unregistered notes had been exchanged for registered notes by October 27, 2008.

In January 2008, we entered into a $350.0 million notional amount interest rate swap agreement with a financial institution that effectively fixed our interest rate on the variable rate term loan at an annual rate of 6.26%. As a result of the exchange of the variable rate term loan to Senior Floating Rate Notes, the interest rate swap is now being used to fix the variable LIBOR interest rate on the Senior Floating Rate Notes at an annual rate of 6.26% through April 2011.

We may redeem some or all of the Senior Floating Rate Notes at specified redemption prices on or after April 1, 2009 and may redeem some or all of the 8.625% Senior Notes at specified redemption prices on or after April 1, 2011.

We incurred $26.1 million of debt issuance costs in connection with the senior term loans. As the senior term loans were exchanged for senior unsecured notes with substantially identical terms, the remaining unamortized debt issuance costs of the senior term loans are being amortized over the term of the 8.625% Senior Notes and the Senior Floating Rate Notes.

8.0% Senior Notes Due 2018. In May 2008, we privately placed $750.0 million of our unsecured 8.0% Senior Notes due 2018. We used $478.0 million of the $735.0 million net proceeds to repay the total balance outstanding at that time on our senior credit facility. The remaining proceeds were used to fund a portion of our 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 notes became freely tradable on November 17, 2008, 180 days after their issuance, pursuant to Rule 144 under the Securities Act.

We incurred $16.0 million of debt issuance costs in connection with the 8.0% Senior Notes. These costs are being amortized over the term of these notes.

Debt covenants under the 8.0% Senior Notes as well as the 8.625% Senior Notes and the Senior Floating Rate Notes include financial covenants similar to those of the senior credit facility. The covenants include limitations on the incurrence of indebtedness, payment of dividends, asset sales, certain asset purchases, transactions with related parties and consolidation or merger agreements. As of December 31, 2008, we were in compliance with all of the covenants under all of the senior notes.

Senior Bridge Facility. On November 21, 2006, we entered into an $850.0 million senior unsecured bridge facility in conjunction with our acquisition of NEG. We repaid this facility in full in March 2007 with proceeds from our senior term loans.

Redeemable Convertible Preferred Stock

Prior to the conversion of our redeemable convertible preferred stock to common stock during 2008, each holder of our redeemable convertible preferred stock was entitled to quarterly cash dividends at the annual rate of 7.75% of the accreted value, $210 per share, of their redeemable convertible preferred stock. Each share of redeemable convertible preferred stock was convertible into approximately 10.2 shares of common stock at the option of the holder, subject to certain anti-dilution adjustments.

During March 2008, holders of 339,823 shares of our redeemable convertible preferred stock elected to convert those shares into 3,465,593 shares of our common stock. In May 2008, we converted the remaining outstanding 1,844,464 shares of our redeemable convertible preferred stock into 18,810,260 shares of our common stock as permitted under the terms of the redeemable convertible preferred stock. These conversions resulted in total charges to retained earnings of $7.2 million in accelerated accretion expense related to the converted redeemable convertible preferred shares. We paid all dividends on our redeemable convertible preferred stock in cash, including $33.3 million in 2007 and $17.6 million in 2008. On and after the conversion date, dividends ceased to accrue and rights of common unit holders to exercise outstanding warrants to purchase shares of redeemable convertible preferred stock terminated.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2008 is provided in the following table:

	Payments Due by Year						
	2009	**2010**	**2011**	**2012**	**2013**	**After 2013**	**Total**
				(In thousands)			
Long-term debt	$ 16,532	$ 12,005	$ 580,751	$ 1,051	$ 1,120	$ 1,763,857	$ 2,375,316
Interest on senior notes(1)	142,339	142,339	142,339	142,339	142,339	341,647	1,053,342
Firm transportation	22,810	36,195	31,320	31,406	25,392	84,688	231,811

Third-party drilling rig commitments(2)	15,832	1,234					17,066
Dispute settlement payments(3)	5,000	5,000	5,000				15,000
Asset retirement obligations	275	6,940	1,211	2,911	446	72,989	84,772
Operating leases and other	1,533	383	530	497	714	2,281	5,938
Total	$ 204,321	$ 204,096	$ 761,151	$ 178,204	$ 170,011	$ 2,265,462	$ 3,783,245

(1) Based on interest rates as of December 31, 2008.

(2) Drilling contracts with third-party drilling rig operators at specified day rates. All of our drilling rig contracts contain operator performance conditions that allow for pricing adjustments or early termination for operator nonperformance.

(3) In January 2007, we settled a royalty interest dispute and agreed to pay five installments of $5 million each, plus interest commencing April 1, 2007. The remaining installments are due on July 1 of each year indicated.

In connection with the NEG acquisition, we acquired restricted deposits representing bank trust and escrow accounts required by surety bond underwriters and certain former owners of NEG s offshore properties. In accordance with MMS requirements, NEG was required to put in place surety bonds or escrow agreements to provide satisfaction of its eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. As part of the agreement with the surety bond underwriter or the former owners of the particular fields, bank trust and escrow accounts were set up and funded based on the terms of the escrow agreements. Certain amounts are required to be paid upon receipt of proceeds from production.

During 2007, funds totaling $10.3 million were released from escrow accounts and returned to us. No escrow funds were returned to us during 2008.

One of the escrow accounts requires us to deposit additional funds in an escrow account equal to 10% of the net proceeds, as defined, from certain of our offshore properties. During 2008, we deposited approximately $0.8 million in the escrow account.

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.

Proved Reserves. Over 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 crude 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, 2008, 2007 and 2006, we revised our proved reserves from prior years reports by approximately 452.6 Bcfe, 351.6 Bcfe and 26.6 Bcfe, respectively, due to market prices 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 depletion, depreciation and amortization expenses.

Method of accounting for natural gas and crude 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 crude oil properties are capitalized. Exploration and development costs include dry hole 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 crude oil reserves. Amortization of natural gas and crude oil properties is provided using the unit-of-production method based on estimated proved natural gas and crude oil reserves. Sales and abandonments of natural gas and crude 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 crude 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, amortization and impairment of oil and natural gas properties are generally calculated on a well by well or 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 crude 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 crude 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). The full cost ceiling limitation is calculated using natural gas and crude oil prices in effect as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. 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. At December 31, 2008, total capitalized costs of our natural gas and crude oil properties exceeded our ceiling limitation resulting in a non-cash ceiling impairment of $1,855.0 million.

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

We recognize revenues and expenses generated from daywork drilling contracts as the services are performed, since we do not bear the risk of completion of the well. Under turnkey contracts, we bear the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the negotiated depth as stated in the contract. The duration of these contracts typically ranges from 20 to 90 days. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on turnkey contracts, which are still in process at the end of the period.

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.

Revenues of our midstream gas services segment are derived from providing supply, transportation, balancing and sales services for producers and wholesale customers on our natural gas pipelines, as well as other interconnected pipeline systems. Midstream gas services are primarily undertaken to realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. 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. Revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determinable and collectability is reasonably assured.

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 bases. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax bases. 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, 2008, we had recorded 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

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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.

Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in natural gas and crude oil prices, we enter into interest rate swaps and natural gas and crude 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 a hedging instrument during 2008, 2007 and 2006.

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 2009 capital expenditures, our liquidity and capital resources, 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 c 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 crude oil prices;
- uncertainties in estimating natural gas and crude oil reserves;
- the need to replace the natural gas and crude 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 crude 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;

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 crude oil wells;

availability of satisfactory natural gas and crude 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***

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

Commodity Price Risk. Our most significant market risk relates to the prices we receive for our natural gas and crude oil production. For example, crude oil prices have declined from a record high of $147.55 per barrel in July 2008 to approximately $33.87 per barrel in December 2008. Meanwhile, natural gas futures prices during 2008 ranged from as high as $14.27 per Mcf in July 2008 to as low as $5.29 per Mcf in December 2008. In light of the historical volatility of these commodities, we periodically have entered into, and expect in the future to enter into, derivative arrangements aimed at reducing the variability of natural gas and crude 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. We currently have seventeen approved derivative counterparties, sixteen of which are lenders under our senior credit facility. We currently have derivative contracts outstanding with twelve of these counterparties. We have no derivative contracts in 2009 and beyond with counterparties outside of those that are also part of our senior credit facility. Lehman Brothers is a counterparty on one of our derivative contracts. Due to the bankruptcy of Lehman Brothers and its parent, Lehman Brothers Holdings, Inc., we did not assign any value to this derivative contract (notional of 7,300 MMcf) at December 31, 2008.

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 NYMEX 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. Settlement for natural gas derivative contracts occurs in the production month.

While we believe that the natural gas and crude oil price derivative arrangements we enter into are important to our program to manage price variability for our production, we have not designated any of our derivative contracts

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as hedges for accounting purposes. We record all derivative contracts on the balance sheet at fair value, which reflects changes in natural gas and crude 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 commodities derivative contracts. Changes in fair value are principally measured based on period-end prices compared to the contract price.

At December 31, 2008, our open natural gas and crude oil commodity derivative contracts consisted of the following:

Natural Gas

Period and Type of Contract	Notional (MMcf)(1)	Weighted Avg. Fixed Price	
January 2009 March 2009			
Price swap contracts	20,700	$	9.14
Basis swap contracts	15,300	$	(0.74)
April 2009 June 2009			
Price swap contracts	20,930	$	7.96
Basis swap contracts	15,470	$	(0.74)
July 2009 September 2009			
Price swap contracts	18,710	$	8.09
Basis swap contracts	15,640	$	(0.74)
October 2009 December 2009			
Price swap contracts	18,400	$	8.54
Basis swap contracts	15,640	$	(0.74)
January 2010 March 2010			
Price swap contracts	16,875	$	8.08
Basis swap contracts	14,400	$	(0.73)
April 2010 June 2010			
Price swap contracts	17,063	$	7.38
Basis swap contracts	14,560	$	(0.73)
July 2010 September 2010			
Price swap contracts	17,250	$	7.61
Basis swap contracts	14,720	$	(0.73)
October 2010 December 2010			
Price swap contracts	17,250	$	8.03
Basis swap contracts	14,720	$	(0.73)
January 2011 March 2011			
Basis swap contracts	1,350	$	(0.47)
April 2011 June 2011			
Basis swap contracts	1,365	$	(0.47)
July 2011 September 2011			
Basis swap contracts	1,380	$	(0.47)
October 2011 December 2011			
Basis swap contracts	1,380	$	(0.47)

(1) Assumes ratio of 1:1 for Mcf to MMBtu and excludes a total notional of 7,300 MMcf from 2009 for the Lehman Brothers basis swap contract.

Crude Oil

Period and Type of Contract	Notional (in MBbls)	Weighted Avg. Fixed Price	
January 2009 March 2009			
Price swap contracts	45	$	126.38
April 2009 June 2009			
Price swap contracts	46	$	126.71
July 2009 September 2009			
Price swap contracts	46	$	126.61
October 2009 December 2009			
Price swap contracts	46	$	126.51

The following table summarizes the cash settlements and valuation gains and losses on our commodity derivative contracts for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	2008		2007		2006	
Realized loss (gain)	$	12,981	$	(34,494)	$	(14,169)
Unrealized (gain) loss		(224,420)		(26,238)		1,878
Gain on derivative contracts	$	(211,439)	$	(60,732)	$	(12,291)

Credit Risk. Credit risk relates to the risk of loss as a result of non-performance by one or more of our counterparties under any of our credit arrangements. Recently, the ability of certain investment banks and other financial institutions to meet their financial obligations has been of increasing concern. A portion of our liquidity is concentrated in derivative contracts that enable us to mitigate a portion of our exposure to natural gas and crude 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.

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 6.31%. 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 availability of amounts 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.

We use sensitivity analysis to determine the impact that market risk exposures may have on our variable interest rate borrowings. Based on the $350.0 million outstanding balance of our Senior Floating Rate Notes at December 31, 2008, 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, 2008.

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 our interest rate on the variable rate term loan for the period from April 1, 2008 through April 1, 2011. As a result of the exchange of the variable rate term loan to Senior Floating Rate Notes, the interest rate swap is being used to fix the variable LIBOR interest rate on the Senior Floating Rate Notes at 6.26% through April 2011. This swap has not been designated as a hedge.

An unrealized loss of $8.7 million was recorded in interest expense in the consolidated statement of operations for the change in fair value of the interest rate swap for the year ended December 31, 2008.

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. We performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures were effective 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 Securities and Exchange Commission 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, 2008 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, 2009: 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, 2009: Director Compensation, Outstanding Equity Awards and Executive Officers and Compensation.

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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, 2009: 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, 2009: 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, 2009.

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.

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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 under the framework established in *Internal Control Integrated Framework*, our management concluded, that as of December 31, 2008, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2008 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by 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 was an integrated audit in 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.

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
February 26, 2009

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Balance Sheets

	December 31, 2008	December 31, 2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 636	$ 63,135
Accounts receivable, net:		
Trade	102,746	94,741
Related parties	6,327	20,018
Derivative contracts	201,111	21,958
Inventories	3,686	3,993
Deferred income taxes		1,820
Other current assets	41,407	20,787
Total current assets	355,913	226,452
Natural gas and crude oil properties, using full cost method of accounting		
Proved	4,676,072	2,848,531
Unproved	215,698	259,610
Less: accumulated depreciation, depletion and impairment	(2,369,840)	(230,974)
	2,521,930	2,877,167
Other property, plant and equipment, net	653,629	460,243
Derivative contracts	45,537	270
Investments	6,088	7,956
Restricted deposits	32,843	31,660
Other assets	39,118	26,818
Total assets	$ 3,655,058	$ 3,630,566
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 16,532	$ 15,350
Accounts payable and accrued expenses:		
Trade	366,337	215,497
Related parties	230	395
Derivative contracts	5,106	
Asset retirement obligation	275	864
Billings in excess of costs incurred	14,144	
Total current liabilities	402,624	232,106
Long-term debt	2,358,784	1,052,299

Other long-term obligations	11,963	16,817
Derivative contracts	3,639	
Asset retirement obligation	84,497	57,716
Deferred income taxes		49,350
Total liabilities	2,861,507	1,408,288
Commitments and contingencies (Note 18)		
Minority interest	30	4,672
Redeemable convertible preferred stock, $0.001 par value, 2,625 shares authorized; no shares issued and outstanding at December 31, 2008 and 2,184 shares issued and outstanding at December 31, 2007		450,715
Stockholders equity:		
Preferred stock, $0.001 par value; 47,375 shares authorized; no shares issued and outstanding in 2008 and 2007		
Common stock, $0.001 par value, 400,000 shares authorized; 167,372 issued and 166,046 outstanding at December 31, 2008 and 143,299 issued and 141,843 outstanding at December 31, 2007	163	140
Additional paid-in capital	2,170,986	1,686,113
Treasury stock, at cost	(19,332)	(18,578)
(Accumulated deficit) retained earnings	(1,358,296)	99,216
Total stockholders equity	793,521	1,766,891
Total liabilities and stockholders equity	$ 3,655,058	$ 3,630,566

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Operations

	Years Ended December 31, 2008	2007	2006
	(In thousands, except per share amounts)		
Revenues:			
Natural gas and crude oil	$ 908,689	$ 477,612	$ 101,252
Drilling and services	47,199	73,197	139,049
Midstream and marketing	207,602	107,765	122,896
Other	18,324	18,878	25,045
Total revenues	1,181,814	677,452	388,242
Expenses:			
Production	159,004	106,192	35,149
Production taxes	30,594	19,557	4,654
Drilling and services	26,186	44,211	98,436
Midstream and marketing	186,655	94,253	115,076
Depreciation, depletion and amortization natural gas and crude oil	290,917	173,568	26,321
Depreciation, depletion and amortization other	70,448	53,541	29,305
Impairment	1,867,497		
General and administrative	109,372	61,780	55,634
Gain on derivative contracts	(211,439)	(60,732)	(12,291)
Gain on sale of assets	(9,273)	(1,777)	(1,023)
Total expenses	2,519,961	490,593	351,261
(Loss) income from operations	(1,338,147)	186,859	36,981
Other income (expense):			
Interest income	3,569	4,694	991
Interest expense	(147,027)	(117,185)	(16,904)
Minority interest	(855)	276	(296)
Income from equity investments	1,398	4,372	967
Other income, net	1,454	729	118
Total other (expense) income	(141,461)	(107,114)	(15,124)
(Loss) income before income tax (benefit) expense	(1,479,608)	79,745	21,857
Income tax (benefit) expense	(38,328)	29,524	6,236
Net (loss) income	(1,441,280)	50,221	15,621
Preferred stock dividends and accretion	16,232	39,888	3,967
(Loss applicable) income available to common stockholders	$ (1,457,512)	$ 10,333	$ 11,654

Basic and Diluted Earnings Per Share:						
Net (loss) income	$	(9.26)	$	0.46	$	0.21
Preferred stock dividends		(0.10)		(0.37)		(0.05)
Basic and diluted (loss) income per share (applicable) available to common stockholders	$	(9.36)	$	0.09	$	0.16
Weighted average number of common shares outstanding:						
Basic		155,619		108,828		73,727
Diluted		155,619		110,041		74,664

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity

	Common Stock	Additional Paid-In Capital	Deferred Compensation	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total
			(In thousands)			
Balance, December 31, 2005	$ 73	$ 243,920	$ (14,885)	$ (17,335)	$ 77,229	$ 289,002
Stock offering		3,343				3,343
Change in accounting principle for stock-based compensation		(14,885)	14,885			
Issuance of stock in acquisitions	13	236,271				236,284
Stock offering, net of $3.9 million in offering costs	6	97,427				97,433
Accretion on redeemable convertible preferred stock					(157)	(157)
Purchase of treasury shares				(500)		(500)
Stock-based compensation		8,792				8,792
Net income					15,621	15,621
Balance, December 31, 2006	92	574,868		(17,835)	92,693	649,818
Stock offerings, net of $4.5 million in offering costs	50	1,113,314				1,113,364
Conversion of common stock to redeemable convertible preferred stock	(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		379		917		1,296
Stock-based compensation		7,202				7,202
Net income					50,221	50,221
Redeemable convertible preferred stock dividends					(42,277)	(42,277)
Balance, December 31, 2007	140	1,686,113		(18,578)	99,216	1,766,891
Accretion on redeemable convertible preferred stock					(7,636)	(7,636)
Conversion of redeemable convertible preferred stock to common stock	23	458,328				458,351
Purchase of treasury stock				(3,553)		(3,553)

Common stock issued under retirement plans		3,167		2,799		5,966
Stock-based compensation		18,784				18,784
Stock-based compensation excess tax benefit		4,594				4,594
Net loss					(1,441,280)	(1,441,280)
Redeemable convertible preferred stock dividends					(8,596)	(8,596)
Balance, December 31, 2008	$ 163	$ 2,170,986	$	$ (19,332)	$ (1,358,296)	$ 793,521

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

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SandRidge Energy, Inc. and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net (loss) income	$ (1,441,280)	$ 50,221	$ 15,621
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Provision for doubtful accounts	1,748		2,528
Depreciation, depletion and amortization	361,365	227,109	55,626
Impairment	1,867,497		
Debt issuance cost amortization	5,623	15,998	299
Deferred income taxes	(47,530)	28,923	348
Provision for inventory obsolescence		203	
Unrealized (gain) loss on derivative contracts	(215,675)	(26,238)	1,878
Gain on sale of assets	(9,273)	(1,777)	(1,023)
Interest income restricted deposits	(402)	(1,354)	(151)
Income from equity investments	(1,398)	(4,372)	(956)
Stock-based compensation	18,784	7,202	8,792
Minority interest	855	(276)	296
Changes in operating assets and liabilities increasing (decreasing) cash:			
Receivables	3,735	(19,061)	(2,648)
Inventories	307	(1,730)	(938)
Other current assets	(20,603)	12,374	(22,238)
Other assets and liabilities, net	127	(5,069)	(2,131)
Accounts payable and accrued expenses	41,165	75,299	12,046
Billings in excess of costs	14,144		
Net cash provided by operating activities	579,189	357,452	67,349
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures for property, plant and equipment	(2,058,415)	(1,280,848)	(306,541)
Acquisitions of assets, net of cash received of $0, $0 and $21,100		(116,650)	(1,054,075)
Proceeds from sale of assets	158,781	9,034	19,742
Proceeds from sale of investments			2,373
Contributions on equity investments	(1,528)		(3,388)
Loans to equity investee	(7,500)		
Refunds of restricted deposits		10,328	
Fundings of restricted deposits	(781)	(7,445)	(1,051)
Restricted cash			2,373
Net cash used in investing activities	(1,909,443)	(1,385,581)	(1,340,567)

CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from borrowings		3,252,209		1,331,541		1,261,910
Repayments of borrowings		(1,944,542)		(1,332,219)		(518,870)
Dividends paid-preferred		(17,552)		(33,321)		
Minority interest distributions		(5,497)		(144)		(618)
Proceeds from issuance of common stock				1,114,660		100,776
Proceeds from issuance of redeemable convertible preferred stock						439,486
Stock-based compensation excess tax benefit		4,594				
Purchase of treasury stock		(3,553)		(1,661)		(500)
Debt issuance costs		(17,904)		(26,540)		(15,749)
Net cash provided by financing activities		1,267,755		1,052,316		1,266,435
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		(62,499)		24,187		(6,783)
CASH AND CASH EQUIVALENTS, beginning of year		63,135		38,948		45,731
CASH AND CASH EQUIVALENTS, end of year	$	636	$	63,135	$	38,948
Supplemental Disclosure of Cash Flow Information:						
Cash paid for interest, net of amounts capitalized	$	131,183	$	83,567	$	15,079
Cash paid for income taxes		2,191		2,371		1,599
Supplemental Disclosure of Noncash Investing and Financing Activities:						
Accrued capital expenditures	$	119,432	$		$	
Redeemable convertible preferred stock dividends, net of dividends paid				8,956		
Insurance premium financed				1,496		5,023
Accretion on redeemable convertible preferred stock		7,636		1,421		157
Common stock issued in connection with acquisitions						236,284
Assumption of restricted deposits and notes payable in connection with acquisition						313,628

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. (successor to Riata Energy, Inc.) and 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 CO_2 treating and transportation facilities and has marketing and tertiary oil recovery operations. In addition, Lariat Services, Inc. (Lariat), a wholly owned subsidiary, 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. 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 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 crude 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 crude 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.

The Company s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for natural gas and crude 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 crude oil prices may be subject to significant fluctuations in the future. A substantial or extended decline in natural gas and crude 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 crude oil reserves that may be economically produced.

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, crude oil and natural gas liquids, as well as receivables related to the exploration and treating services for natural gas, crude 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.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

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.

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 approximately $38.2 million as of December 31, 2008 and approximately $26.0 million as of December 31, 2007. The Company includes the unamortized costs in other assets in its consolidated balance sheets.

Revenue Recognition and Gas Balancing. Natural gas and crude 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 crude oil production imbalances using the sales method, whereby the Company recognizes revenue on all natural gas and crude oil sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas and crude oil sold. Liabilities are recorded by the Company for imbalances greater than the Company s proportionate share of remaining estimated natural gas and crude oil reserves. The Company has recorded a liability for gas imbalance positions related to natural gas properties with insufficient proved reserves of $1.7 million and $1.6 million at December 31, 2008 and 2007, 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 daywork drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. Under turnkey contracts, the Company bears the risk of completion of the well; therefore, revenues and expenses are recognized when the well is substantially completed. Under this method, substantial completion is determined when the well bore reaches the depth stated in the contract. The duration of daywork and turnkey contracts typically ranges from 20 to 90 days. The entire amount of a loss, if any, is recorded when the loss is determinable. The costs of uncompleted drilling contracts include expenses incurred to date on turnkey contracts that are still in process at the end of the period.

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.

Revenues from the midstream services segment are derived from providing gathering, compression, treating, balancing and sales services for producers and wholesale customers on its natural gas gathering systems. Midstream gas services are primarily undertaken to realize incremental margins on natural gas purchased at the wellhead and provide value-added services to customers. In general, natural gas purchased and sold by the midstream gas business is priced at a published daily or monthly index price plus or minus a negotiated differential. 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 determinable 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, 2008 and 2007 were not material.

Natural Gas and Crude Oil Operations. The Company uses the full cost method to account for its natural gas and crude oil properties. Under full cost accounting, all costs directly associated with the acquisition, exploration

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

and development of natural gas and crude 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 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 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. No internal costs or interest expense were capitalized to the full cost pool in 2006.

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 total unamortized 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 crude 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 crude 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 crude 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.

The ceiling limitation calculation uses natural gas and crude 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 (net wellhead prices). 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 crude oil. The Company may, from time-to-time, use derivative financial instruments to hedge against the volatility of natural gas and crude 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 holes are transferred to the amortization base immediately upon determination that the well is unsuccessful.

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 crude oil properties that require expenditures to plug and abandon the wells when the natural gas and crude 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 crude 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. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the related asset. The following shows the activity of the asset retirement obligation for the years ended December 31 (in thousands).

	2008	2007	2006
Asset retirement obligation, January 1	$ 58,580	$ 45,216	$ 6,979

Liability incurred upon acquiring and drilling wells	5,707	3,265	2,996
NEG acquisition			40,343
Revisions in estimated cash flows	15,976	5,971	(5,700)
Liability settled in current period	(764)	(9)	
Accretion of discount expense	5,273	4,137	598
Asset retirement obligation, December 31	84,772	58,580	45,216
Less: current portion	275	864	
Asset retirement obligation, net of current	$ 84,497	$ 57,716	$ 45,216

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SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

The revisions in estimated cash flows for 2008 are primarily due to changes in reserve lives based on lower natural gas and crude oil prices at December 31, 2008.

Income Taxes. Deferred income taxes are recorded for temporary differences between financial reporting purposes and income tax bases. Temporary differences are differences between the amounts of assets and liabilities reported for financial reporting purposes and their tax bases. 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.

The Company accounts for uncertain tax positions in accordance with Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes . Accordingly, the Company reports a liability for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return.

The Company has elected an accounting policy in which interest and penalties on income tax related balances are presented as a component of income taxes.

Minority Interest. At December 31, 2008 and 2007, minority interest in the Company s consolidated subsidiaries included a 1.29% interest in Cholla Pipeline, LP. At December 31, 2007, minority 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 minority 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. At December 31, 2008, Barclays Capital, JPMorgan Chase Bank, Bank of America, Morgan Stanley, Bank of Montreal and Credit Suisse were the counterparties with respect to 81.7% of the Company s hedged future production.

The purchasers of the Company s natural gas and crude 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 2008 and 2007, the Company had one individual purchaser accounting for 10.5% and 11.2%, respectively, of its total sales. In 2006, the Company had no individual purchasers accounting for more than 10% 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 crude oil it produces.

Fair Value of Financial Instruments. The fair values of the Company s cash and cash equivalents, accounts receivable and accounts payable approximate their carrying amounts due to their short-term nature. The fair value for the Company s publicly traded senior notes, which was based on market prices, was $961.3 million (carrying value of $1.750 billion) at December 31, 2008. The Company s carrying value for its senior credit facility and remaining fixed rate debt instruments approximates fair value based on current rates applicable to similar instruments. The Company measured fair value of its long-term debt in accordance with Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements, giving consideration to the effect of the

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Company s credit risk. The estimated fair values of derivative contracts are based on quotes obtained from the counterparties to the derivative contracts. See Note 3.

Derivative Financial Instruments. To manage risks related to increases in interest rates and changes in natural gas and crude oil prices, the Company enters into interest rate swaps and natural gas and crude 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 2008, 2007 and 2006.

Stock-Based Compensation. Effective January 1, 2006, the Company adopted SFAS No. 123R, Share-Based Payment. SFAS No. 123R establishes the accounting for equity instruments exchanged for employee services. Under SFAS No. 123R, stock-based compensation cost is measured based on the calculated fair value of the award on the grant date. The expense is recognized over the employee s requisite service period, generally the vesting period of the award. SFAS No. 123R also requires the related excess tax benefit received upon exercise of stock options or vesting of restricted stock, if any, to be reflected in the statement of cash flows as a financing activity rather than as an operating activity. As of December 31, 2008, the Company had $4.6 million of excess tax benefits related to stock-based compensation.

Recent Accounting Pronouncements. Effective January 1, 2008, SandRidge implemented SFAS No. 157 for its financial assets and liabilities measured on a recurring basis. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands required disclosures about fair value measurements. SFAS No. 157 did not have an effect on the Company s financial statements on the date of adoption other than requiring additional disclosures regarding fair value measurements. See Note 3.

In February 2008, the FASB issued Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 (FSP 157-2). FSP 157-2 delays the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. The Company plans to implement this standard on January 1, 2009. The adoption of FSP 157-2 is not expected to have a material impact on the Company s financial condition, operations or cash flows.

Effective upon issuance, the FASB issued Staff Position FAS 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active, (FSP 157-3) in October 2008. FSP 157-3 clarifies the application of SFAS No. 157 in determining the fair value of a financial asset when the market for that financial asset is not active. As of December 31, 2008, the Company had no financial assets with a market that was not active. Accordingly, FSP 157-3 had no effect on the Company s current financial statements.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations, which replaces SFAS No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS No. 141(R) also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for business combinations with acquisition dates on or after fiscal years beginning after December 15, 2008. The Company will evaluate this standard with respect to business combinations with acquisition dates on or after January 1, 2009.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an Amendment of Accounting Research Bulletin No. 51, which establishes 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. SFAS No. 160 also establishes disclosure requirements to clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. The Company plans to implement this standard on January 1, 2009. The implementation of SFAS No. 160 is not expected to have a material impact on the Company s financial condition or operations as the effect will be on presentation and disclosure.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, which changes disclosure requirements for derivative instruments and hedging activities. SFAS No. 161 requires enhanced disclosure, including 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. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008. The Company plans to implement this standard on January 1, 2009. As SFAS No. 161 pertains to disclosure requirements, no effect to the Company s financial condition, operations or cash flows is expected.

On December 31, 2008, the Securities and Exchange Commission (SEC) issued Release No. 33-8995, Modernization of Oil and Gas Reporting, which revises disclosure requirements for oil and gas companies. In addition to changing the definition and disclosure requirements for oil and gas reserves, the new rules change the requirements for determining oil and gas reserve quantities. These rules permit the use of new technologies to determine proved reserves under certain criteria and allow companies to disclose their probable and possible reserves. The new rules also require companies to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conducts a reserves audit. The new rules also require that oil and gas reserves be reported and the full cost ceiling limitation be calculated using a twelve-month average price rather than period-end prices. The use of a twelve-month average price could have had an effect on the Company s 2008 depletion rates for its natural gas and crude oil properties. The new rule is effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, pending the potential alignment of certain accounting standards by the FASB with the new rule. The Company plans to implement the new requirements in its Annual Report on Form 10-K for the year ended December 31, 2009. The Company is currently evaluating the impact of this new rule on its consolidated financial statements.

2. Acquisitions and Dispositions

2006 Acquisitions and Dispositions

The Company closed the following acquisitions in 2006:

> In March 2006, the Company acquired from an executive officer and director an additional 12.5% interest in PetroSource Energy Company, LLC (PetroSource), a consolidated subsidiary. The acquisition consisted of the retirement of subordinated debt of approximately $1.0 million and a $4.5 million cash payment for the ownership interest acquired for a total acquisition price of approximately $5.5 million.

In May 2006, the Company purchased certain leases in developed and undeveloped properties from an oil and gas company. The purchase price was approximately $40.9 million in cash. The cash consideration was paid in July 2006.

In May 2006, the Company purchased several natural gas and crude oil properties from an oil and gas company. The purchase price was approximately $12.9 million, comprised of $8.2 million in cash, and

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

251,351 shares of Company common stock, valued at $4.7 million. The cash and equity consideration were paid in July 2006.

In June 2006, the Company purchased certain producing well interests from an executive officer and director. The purchase price was approximately $9.0 million in cash.

In June 2006, the Company acquired the remaining 1% interest in PetroSource from an oil and gas company. The purchase price was 27,749 shares of Company common stock, valued at $0.5 million. As a result of this acquisition, the Company became the 100% owner of PetroSource.

The 2006 acquisitions described above were financed with approximately $63.7 million in cash and the issuance of 279,100 shares of common stock with an aggregate value of approximately $5.1 million. Details are set forth below for each of the acquisition transactions (in thousands):

				Consideration Paid		
Acquisition Transaction	**Addition to Property, Plant &Equipment**	**Change in Minority Interest**	**Retirement of Subordinated Debt(1)**	**Common Stock No. of Shares**	**Common Stock**	**Cash**
PetroSource additional interests	$ 2,116	$ (2,370)	$ (1,003)		$	$ 5,489
Purchased leases	40,960					40,960
Natural gas and crude oil properties	12,850			251	4,650	8,200
Producing well interest from executive officer and director	9,000					9,000
PetroSource additional interest (remaining 1% interest)	85	(393)		28	478	
Totals	$ 65,011	$ (2,763)	$ (1,003)	279	$ 5,128	$ 63,649

(1) Includes retirement of subordinated debt of $972,000 and accrued interest of $31,000.

In July 2006, the Company sold leaseholds and lease and well equipment for $16.0 million. The book basis of the assets at the time of the sale transaction was $3.7 million resulting in a gain of $12.3 million. The sale was accounted for as an adjustment to the full cost pool, with no gain recognized.

In November 2006, the Company acquired all of the outstanding membership interests in NEG Oil & Gas LLC (NEG) for approximately $990.4 million in cash, the assumption of $300.0 million in debt, the receipt of cash of $21.1 million and the issuance of 12,842,000 shares of the Company s common stock, valued at approximately $231.2 million. To finance the NEG acquisition, the Company entered into a $750.0 million senior secured credit facility and an $850.0 million senior unsecured bridge loan facility. The Company also issued $550.0 million of redeemable convertible preferred stock and common units, consisting of shares of common stock and a warrant to purchase convertible preferred stock upon the surrender of the common stock, in a private placement to certain eligible purchasers.

In the fourth quarter of 2007, the Company completed its valuation of assets acquired and liabilities assumed related to the NEG acquisition and allocated the appropriate fair values. Upon further refinement of the appraisal values, the Company increased its values assigned to the properties acquired and reduced the value assigned to goodwill of $26.2 million. The allocation of the purchase price to specific assets and liabilities were based, in part, upon an appraisal of the fair value of NEG assets.

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Notes to Consolidated Financial Statements (Continued)

The following table presents the final NEG acquisition purchase price allocation, including professional fees and other related acquisition costs, to the net assets acquired and liabilities assumed, based on the fair values at the acquisition date and including subsequent adjustments to the purchase price allocation (in thousands):

Cash and cash equivalents	$ 21,100
Accounts receivable	30,840
Other current assets	6,025
Property, plant and equipment	1,524,072
Restricted deposits	31,987
Other assets	270
Total assets acquired	1,614,294
Accounts payable and other current liabilities	46,082
Deferred income taxes	2,189
Long-term debt	281,641
Other long-term obligations	1,357
Asset retirement obligation	40,343
Net assets acquired	1,242,682
Less: Cash and cash equivalents acquired	(21,100)
Net amount paid for acquisition	$ 1,221,582

Pro Forma Information

The unaudited financial information in the table below summarizes the combined results of operations of SandRidge and NEG, on a pro forma basis, as though the companies had been combined as of January 1, 2006. The pro forma financial information is presented for informational purposes only and does not necessarily reflect the results of operations that would have been achieved if the acquisition had taken place on January 1, 2006 or the results that may occur in the future. The pro forma adjustments include estimates and assumptions based on currently available information. The Company believes the estimates and assumptions are reasonable, and the significant effects of the transactions are properly reflected. However, actual results may have differed materially from this pro forma financial information. The following table presents the actual results for the year ended December 31, 2006 and the respective unaudited pro forma information to reflect the NEG acquisition (in thousands, except per share amounts):

	Year Ended December 31, 2006	
	Actual	Pro Forma
	(Unaudited)	
Revenues	$ 388,242	$ 565,256

Net income	$	15,621	$	36,337
Basic and diluted earnings per share available to common stockholders:				
Income from operations	$	0.21	$	0.40
Net income available to common stockholders	$	0.16	$	0.04

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

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 approximately $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.

3. Fair Value Measurements

Effective January 1, 2008, the Company implemented SFAS No. 157 for its financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and liabilities that are measured and reported on a fair value basis. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for certain nonfinancial assets and liabilities.

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

measurements. SFAS No. 157 requires fair value measurements to be classified and disclosed in one of the following categories:

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

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: Measured based on prices or valuation models that required 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).

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. 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 under SFAS No. 157. 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.

As required by SFAS No. 157, the Company has classified its derivative contracts into one of three levels based upon the data relied upon to determine the fair value. The fair values of the Company s natural gas and crude oil swaps, crude oil collars and interest rate swap 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 specific valuation models used by the counterparties. Included in these models are discount factors that the Company must estimate in its calculation. Additionally, the Company applies a 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 valuation of the Company s financial assets and liabilities as of December 31, 2008 (in thousands):

	Fair Value Measurements Using:			
Description	**Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets/ (Liabilities) at Fair Value**
Assets (liabilities):				
	$	$	$ 246,648	$ 246,648

Natural gas and crude oil derivative contracts								
Interest rate swap						(8,745)		(8,745)
	$		$		$	237,903	$	237,903

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Notes to Consolidated Financial Statements (Continued)

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, 2008 (in thousands):

	Derivatives
Balance of Level 3, December 31, 2007	$ 22,228
Total gains or losses (realized/unrealized)	203,998
Purchases, issuances and settlements	11,677
Transfers in and out of Level 3	
Balance of Level 3, December 31, 2008	$ 237,903
Changes in unrealized gains (losses) on derivative contracts held as of December 31, 2008	$ 215,675

4. Accounts Receivable

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

	December 31, 2008	December 31, 2007
Natural gas and crude oil sales	$ 72,266	$ 72,393
Natural gas and oil services	20,476	6,622
Joint interest billing	13,816	17,874
Other	62	90
	106,620	96,979
Less allowance for doubtful accounts	(3,874)	(2,238)
Total trade accounts receivable, net	$ 102,746	$ 94,741

The following table shows the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2006, 2007 and 2008 (in thousands).

	Balance at Beginning	Additions Charged to Costs and		Balance at End of

Allowance for Doubtful Accounts	of Period	Expenses	Deductions(1)	Period
Year ended December 31, 2006	$ 851	$ 2,528	$ (354)	$ 3,025
Year ended December 31, 2007	$ 3,025	$	$ (787)	$ 2,238
Year ended December 31, 2008	$ 2,238	$ 1,748	$ (112)	$ 3,874

(1) Deductions represent the 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 the third quarter of 2008, the Company established an allowance in the amount of $1.5 million for all amounts due from SemGroup.

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Notes to Consolidated Financial Statements (Continued)

5. Other Current Assets

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

	December 31, 2008	December 31, 2007
Prepaid insurance	$ 9,374	$ 9,379
Prepaid drilling	2,657	5,924
Materials and supplies	155	4,751
Deposits	26,806	60
Other	2,415	673
Total other current assets	$ 41,407	$ 20,787

6. Property, Plant and Equipment

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

	December 31, 2008	December 31, 2007
Natural gas and crude oil properties:		
Proved	$ 4,676,072	$ 2,848,531
Unproved	215,698	259,610
Total natural gas and crude oil properties	4,891,770	3,108,141
Less accumulated depreciation, depletion and impairment(1)	(2,369,840)	(230,974)
Net natural gas and crude oil properties capitalized costs	2,521,930	2,877,167
Land	11,250	1,149
Non natural gas and crude oil equipment	764,792	539,893
Buildings and structures	71,859	38,288
Total	847,901	579,330
Less accumulated depreciation, depletion and amortization	(194,272)	(119,087)
Net capitalized costs	653,629	460,243
Total property, plant and equipment	$ 3,175,559	$ 3,337,410

(1) Includes ceiling limitation impairment charge of $1,855.0 million at December 31, 2008.

The amount of capitalized interest included in the above non natural gas and crude oil equipment balance at December 31, 2008 and 2007 was approximately $3.8 million and $3.4 million, respectively.

In July 2007, the Company purchased property to serve as its corporate headquarters. The 3.51-acre site contains four buildings and is located in downtown Oklahoma City, Oklahoma. The purchase price was approximately $29.5 million in cash.

In May 2008, the Company completed the sale of all of its assets located in the Piceance Basin of Colorado. See Note 2.

The average composite rates used for depreciation, depletion and amortization were $2.82 per Mcfe in 2008, $2.64 per Mcfe in 2007 and $1.68 per Mcfe in 2006.

SandRidge Energy, Inc. and Subsidiaries

Notes to Consolidated Financial Statements (Continued)

Costs Excluded from Amortization

Costs associated with unproved properties of $215.7 million as of December 31, 2008 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 crude oil properties being amortized at December 31, 2008 and the year in which they were incurred:

	Year Cost Incurred			Excluded Costs at December 31,
	2006	2007	2008	2008
Property acquisition	$ 179,888	$	$ 35,810	$ 215,698
Exploration				
Development				
Capitalized interest				
Total costs incurred	$ 179,888	$	$ 35,810	$ 215,698

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. Investment in Affiliated Companies

The Company accounts for certain investments under the equity method when the Company owns more than 20% and has significant influence, but does not control the investee company. The Company s equity method investments include the following:

Grey Ranch, L.P. Grey Ranch, L.P. (Grey Ranch) is primarily engaged in treating and transportation of natural gas. The Company purchased its investment during 2003. At December 31, 2008 and 2007, the Company owned 50% of Grey Ranch and had approximately $6.1 million and $4.2 million, respectively, recorded in the consolidated balance sheets relating to this investment.

Larclay, L.P. The Company and Clayton Williams Energy, Inc. (CWEI) each own a 50% interest in Larclay, L.P. (Larclay), a limited partnership formed to acquire drilling rigs and provide land drilling services. The Company serves as the operations manager of the partnership. CWEI was responsible for securing financing and the purchase of the rigs. The partnership financed the acquisition cost of the rigs with a loan from a third party, secured by the purchased rigs, and a loan from CWEI. In addition, CWEI has guaranteed a portion of the third party debt. As a result of current economic conditions and the resulting on-going cash shortfalls experienced by Larclay, the Company recorded an impairment for its investment in Larclay as of December 31, 2008. See Note 8 for a discussion of impairment. At December 31, 2007, the Company had approximately $3.8 million included in the consolidated balance sheets relating to this investment.

8. Impairment

Full Cost Ceiling Limitation. Under the full cost method of accounting, the net book value of oil and gas 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 crude oil properties, excluding future cash outflows associated with settling asset retirement obligations included in the net book value of natural gas and crude oil properties, plus the cost of properties not subject to amortization. In calculating future net revenues, prices and costs used are those as of the end of the appropriate 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

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Notes to Consolidated Financial Statements (Continued)

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 as of December 31, 2008.

The net book value, less related deferred tax liabilities, is compared to the ceiling limitation on 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 crude oil prices may have increased the ceiling limitation in the subsequent period.

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 the full cost ceiling limitations. The after-tax effect of this reduction in 2008 was $1,677.5 million.

Larclay, L.P. Lariat and CWEI each own a 50% interest in Larclay, a limited partnership formed in 2006 to acquire drilling rigs and provide land drilling services. At December 31, 2008, Lariat s investment in Larclay was $4.8 million. 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 crude oil prices in the fourth quarter of 2008, the demand for Larclay s drilling rigs and land drilling services has decreased. Due to current economic conditions, current natural gas and crude oil prices and the continued cash shortfalls for Larclay, Lariat has fully impaired both the investment in and notes receivable due from Larclay as of December 31, 2008. This resulted in an impairment expense of approximately $12.5 million included in the consolidated statement of operations.

9. Restricted Deposits