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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

OR

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

Commission file number: 001-12719

GOODRICH PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**76-0466193**

(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
801 Louisiana, Suite 700 Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 780-9494 (Registrant s telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, par value $0.20 per share	New York Stock Exchange
(Title of Class)	***(Name of Exchange)***

Securities Registered Pursuant to Section 12(g) of the Act:

Series B Preferred Stock, $1.00 par value

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

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

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 x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

Large accelerated filer ¨ Accelerated filer x Non-accelerated filer ¨ Small reporting company ¨

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

The aggregate market value of Common Stock, par value $0.20 per share (Common Stock), held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2011) the last business day of the registrant s most recently completed second fiscal quarter was approximately $464 million. The number of shares of the registrant s common stock outstanding as of February 10, 2012 was 36,369,685.

Documents Incorporated By Reference:

Portions of Goodrich Petroleum Corporation s definitive Proxy Statement, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2011, are incorporated by reference in Part III of this Form 10-K.

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GOODRICH PETROLEUM CORPORATION

ANNUAL REPORT ON FORM 10-K

FOR THE FISCAL YEAR ENDED

December 31, 2011

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PART I

Items 1. and 2. *Business and Properties*

General

Goodrich Petroleum Corporation (together with its subsidiary, we, our, or the Company) is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in Northwest Louisiana, East Texas and South Texas. The geological formations we target are the Haynesville Shale and Cotton Valley Taylor Sand in Northwest Louisiana and East Texas, the Eagle Ford Shale and Buda Lime formations in South Texas and the Tuscaloosa Marine Shale in Southeast Louisiana and Southwest Mississippi. In the current natural gas price environment, we are concentrating the vast majority of our development efforts on existing leased acreage within formations that are prospective for oil. In addition, we continue to aggressively pursue the evaluation and acquisition of prospective acreage and oil and natural gas drilling opportunities outside of our existing leased acreage. We own working interests in 401 producing oil and natural gas wells located in 29 fields in five states. At December 31, 2011, we had estimated proved reserves of approximately 463.5 Bcf of natural gas, 0.5 MMBbls of natural gas liquids (NGLs) and 5.8 MMBbls of oil and condensate.

We operate as one segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined by accounting standards related to disclosures about segments of an enterprise and related information.

Available Information

Our principal executive offices are located at 801 Louisiana Street, Suite 700, Houston, Texas 77002.

Our website address is *http://www.goodrichpetroleum.com.* We make available, free of charge through the Investor Relations portion of our website, annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (the Exchange Act) as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (SEC). Reports of beneficial ownership filed pursuant to Section 16(a) of the Exchange Act are also available on our website. Information contained on our website is not part of this report.

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the SEC under the Exchange Act. The public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC at *http://www.sec.gov*.

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GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

As used herein, the following terms have specific meanings as set forth below:

Bbls	Barrels of crude oil or other liquid hydrocarbons
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
MBbls	Thousand barrels of crude oil or other liquid hydrocarbons
Mcf	Thousand cubic feet of natural gas
Mcfe	Thousand cubic feet equivalent
MMBbls	Million barrels of crude oil or other liquid hydrocarbons
MMBtu	Million British thermal units
Mmcf	Million cubic feet of natural gas
Mmcfe	Million cubic feet equivalent
MMBoe	Million barrels of crude oil or other liquid hydrocarbons equivalent
NGL	Natural gas liquids
SEC	United States Securities and Exchange Commission
U.S.	United States

Crude oil and other liquid hydrocarbons are converted into cubic feet of gas equivalent based on six Mcf of gas to one barrel of crude oil or other liquid hydrocarbons.

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

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

Economically producible as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil-and-gas producing activities.

Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well or a stratigraphic test well.

Farm-in or farm-out is an agreement whereby the owner of a working interest in an oil and natural gas lease or license assigns the working interest or a portion thereof to another party who desires to drill on the leased or licensed acreage. Generally, the assignee is required to drill one or more wells to earn its interest in the acreage. The assignor (the farmor) usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in, while the interest transferred by the assignor is a farm-out.

Field is an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. The SEC provides a complete definition of field in Rule 4-10 (a) (15).

PV-10 is the pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying the 12-month average price for the year and holding that price constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). Year-end PV-10 is a Non-GAAP financial measure.

Productive well is an exploratory, development or extension well that is not a dry well.

Proved reserves are those quantities of oil and natural gas which, by analysis of geosciences and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. As used in this definition, existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The prices shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future reconditions. The SEC provides a complete definition of proved reserves in Rule 4-10 (a) (22) of Regulation S-X.

Developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well.

Reasonable certainty means a high degree of confidence that the quantities will be recovered, if deterministic methods are used. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geosciences (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease. The deterministic method of estimating reserves or resources uses a single value for each parameter (from the geosciences, engineering, or economic data) in the reserves calculation. The probabilistic method of estimation of reserves or resources uses the full range of values that could reasonably occur for each unknown parameter (from the geosciences and engineering data) to generate a full range of possible outcomes and their associated probabilities of occurrence.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.

Undeveloped reserves are proved 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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances shall estimates for 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 projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

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Working interest is the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover is a series of operations on a producing well to restore or increase production.

Gross well or acre is a well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest.

Net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers.

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Oil and Natural Gas Operations and Properties

Overview. As of December 31, 2011, nearly all of our proved oil and natural gas reserves were located in Northwest Louisiana, East Texas and South Texas. We spent substantially all of our 2011 capital expenditures of $328 million in these areas, with $171 million or 52% spent on the Eagle Ford Shale Trend, and $140 million or 43% spent on the Haynesville Shale Trend. We also spent $16 million, or 5% of our capital expenditures on the Tuscaloosa Marine Shale Trend and $1 million on other areas. Our total capital expenditures, including accrued costs for services performed during 2011, consist of $294 million for drilling and completion costs, $23 million for leasehold acquisition, $9 million for facilities and infrastructure, $1 million for geological and geophysical costs and $1 million for furniture, fixtures and equipment.

The table below details our acreage positions, average working interest and producing wells as of December 31, 2011.

	Acreage As of December 31, 2011		Average Working	Producing Wells at December 31,
Field or Area	Gross	Net	Interest	2011
Eagle Ford Shale Trend	54,744	38,725	72%	24
Cotton Valley Taylor Sand	100,329	81,596	92%	11
Haynesville Shale Trend	126,946	83,320	48%	89
Tuscaloosa Marine Shale	101,800	80,213	79%	
Other	34,436	7,582	38%	277

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Eagle Ford Shale Trend

As of December 31, 2011, we have acquired or farmed-in leases totaling approximately 54,700 gross (38,700 net) lease acres. In 2010 we began development and production activity in the Eagle Ford Shale and Buda Lime formations (Eagle Ford Shale Trend) in La Salle and Frio Counties located in South Texas. During 2011, we drilled 20 gross (14 net) oil wells, with a 100% success rate.

Cotton Valley Taylor Sand

As of December 31, 2011, we have acquired or farmed-in leases totaling approximately 100,300 gross (81,600 net) lease acres in the Cotton Valley Taylor Sand Trend. During 2011, we drilled and completed four gross (four net) wells, with a 100% success rate.

Haynesville Shale Trend

As of December 31, 2011, we have acquired or farmed-in leases totaling approximately 126,900 gross (83,300 net) acres in the Haynesville Shale. During 2011, we drilled 19 gross (five net) successful Haynesville Shale wells. Our Haynesville Shale drilling activities are located in five primary leasehold areas in East Texas and Northwest Louisiana.

In December 2010, we sold a significant amount of our shallow rights in fields in East Texas and Northwest Louisiana, but retained ownership of all the deep rights including the Haynesville and Bossier Shale formations. The sale resulted in net proceeds of $64.9 million, after normal closing adjustments.

Tuscaloosa Marine Shale

During 2011, we acquired approximately 101,800 gross (80,200 net) lease acres in the Tuscaloosa Marine Shale Trend, an emerging oil shale play in East Feliciana, West Feliciana, St. Helena and Washington parishes in Southeast Louisiana and Wilkinson, Pike and Amite Counties in Southwest Mississippi. We anticipate participating in two to six non-operated wells and drilling two operated wells in 2012.

Other

As of December 31, 2011, we maintained ownership interests in acreage and/or wells in several additional fields including: the Midway field in San Patricio County, Texas and the Garfield Unit in Kalkaska County, Michigan.

See Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report on Form 10-K for additional information on our recent operations and plans for 2012 in the Haynesville Shale, Eagle Ford Shale and Tuscaloosa Marine Shale Trends.

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Oil and Natural Gas Reserves

The following tables set forth summary information with respect to our proved reserves as of December 31, 2011 and 2010, as estimated by Netherland, Sewell & Associates, Inc. (NSAI), our independent reserve engineers. A copy of their summary reserve report for 2011 is included as an exhibit to this Annual Report on Form 10-K. For additional information see *Supplemental Information Oil and Natural Gas Producing Activities (Unaudited) to our consolidated financial statements in Part II Item 8 of this Annual Report on Form 10-K.*

	Proved Reserves at December 31, 2011 (dollars in thousands)			
	Developed Producing	**Developed Non-Producing**	**Undeveloped**	**Total**
Net Proved Reserves:				
Oil (MBbls) (1)	2,331	223	3,151	5,705
NGL (MBbls) (4)	197	29	323	549
Natural Gas (Mmcf)	177,273	18,065	268,167	463,505
Natural Gas Equivalent (Mmcfe) (2)	192,440	19,574	289,014	501,028
Estimated Future Net Cash Flows				$ 1,046,891
PV-10 (3)				$ 454,327
Discounted Future Income Taxes				(4,007)
Standardized Measure of Discounted Net Cash Flows (3)				$ 450,320

	Proved Reserves at December 31, 2010 (dollars in thousands)			
	Developed Producing	**Developed Non-Producing**	**Undeveloped**	**Total**
Net Proved Reserves:				
Oil (MBbls) (1)	703	43	872	1,618
Natural Gas (Mmcf)	161,051	26,366	266,772	454,189
Natural Gas Equivalent (Mmcfe) (2)	165,269	26,623	272,007	463,899
Estimated Future Net Cash Flows				$ 897,989
PV-10 (3)				$ 362,126
Discounted Future Income Taxes				(3,448)
Standardized Measure of Discounted Net Cash Flows (3)				$ 358,678

(1) Includes condensate.
(2) Based on ratio of six Mcf of natural gas per Bbl of oil and per Bbl of NGLs.
(3) PV-10 represents the discounted future net cash flows attributable to our proved oil and natural gas reserves before income tax, discounted at 10%. PV-10 of our total year-end proved reserves is considered a non-GAAP financial measure as defined by the SEC. We believe that the presentation of the PV-10 is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account future corporate income taxes and our current tax structure. We further believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our reserves to other companies. Our standardized measure of discounted future net cash flows of proved reserves, or standardized measure, as of December 31, 2011 was $450.3 million. See the reconciliation of our PV-10 to the standardized measure of discounted future net cash flows in the table above.

(4) NGL reserves for 2011 relate to our Eagle Ford Shale Trend, we had no NGL reserves in 2010.

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The following table presents our reserves by targeted geologic formation in Mmcfe.

	December 31, 2011			
Area	**Proved Developed**	**Proved Undeveloped**	**Proved Reserves**	**% of Total**
Haynesville Shale Trend	85,949	149,386	235,335	47%
Cotton Valley Taylor Sand Trend	36,476	106,714	143,190	29%
Eagle Ford Shale Trend	15,844	19,715	35,559	7%
Other	73,745	13,199	86,944	17%
Total	212,014	289,014	501,028	100%

Reserve engineering is a subjective process of estimating underground accumulations of crude oil, condensate and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas sales prices may differ from those assumed in these estimates. Therefore, the PV-10 amounts shown above should not be construed as the current market value of the oil and natural gas reserves attributable to our properties.

In accordance with the guidelines of the SEC, our independent reserve engineers estimates of future net revenues from our estimated proved reserves, and the PV-10 and standardized measure thereof, were determined to be economically producible under existing economic conditions, which requires the use of the 12-month average price for each product, calculated as the unweighted arithmetic average of the first-day-of-the-month price for the period January 2011 through December 2011, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. For reserves at December 31, 2011, the average twelve month prices used were $4.12 per MMBtu of natural gas and $92.71 per Bbl of crude oil/condensate. These prices do not include the impact of hedging transactions, nor do they include the adjustments that are made for applicable transportation and quality differentials, and price differentials between natural gas liquids and oil, which are deducted from or added to the index prices on a well by well basis in estimating our proved reserves and related future net revenues.

Our proved reserve information as of December 31, 2011 included in this Annual Report on Form 10-K was estimated by our independent petroleum consultant, NSAI, in accordance with petroleum engineering and evaluation principles and definitions and guidelines set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserve Information promulgated by the Society of Petroleum Engineers. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Natural Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our principal engineer has over 30 years of experience in the oil and natural gas industry, including over 25 years as a reserve evaluator, trainer or manager. Further professional qualifications of our principal engineer include a degree in petroleum engineering, extensive internal and external reserve training, and experience in asset evaluation and management. In addition, the principal engineer is an active participant in professional industry groups and has been a member of the Society of Petroleum Engineers for over 30 years.

Our estimates of proved reserves are made by NSAI, as our independent petroleum engineers. Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. In addition, other pertinent data such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria is provided to them. We make available all information requested, including our pertinent personnel, to the external engineers as part of their evaluation of our reserves.

We consider providing independent fully engineered third-party estimate of reserves from a nationally reputable petroleum engineering firm, such as NSAI, to be the best control in ensuring compliance with Rule 4-10 of Regulation S-X for reserve estimates.

While we have no formal committee specifically designated to review reserves reporting and the reserves estimation process, a preliminary copy of the NSAI reserve report is reviewed by our senior management with representatives of NSAI and our internal technical staff. Additionally, our senior management reviews and approves any internally estimated significant changes to our proved reserves semi-annually.

Proved reserves are those quantities of oil and natural gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, NSAI employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, available downhole and production data, seismic data and well test data.

Our total proved reserves at December 31, 2011, as estimated by NSAI, were 501 Bcfe, consisting of 464 Bcf of natural gas, 0.5 MMBbls of NGLs and 5.8 MMBbls of oil and condensate. In 2011 we added approximately 48 Bcfe related to the Haynesville Shale Trend and Cotton Valley Taylor Sand Trend, 37 Bcfe related to the Eagle Ford Shale Trend and 21 Bcfe in other areas. We had negative revisions of approximately 29 Bcfe and produced 40 Bcfe in 2011.

Our proved undeveloped reserves at December 31, 2011 were 289 Bcfe or 58% of our total proved reserves, consisting of 268 Bcf of natural gas, 0.3 MMBbls of NGLs and 3.2 MMBbls of oil and condensate. In 2011 we added approximately 21 Bcfe related to the Haynesville Shale Trend, 20 Bcfe related to the Eagle Ford Shale Trend and 14 Bcfe in other areas. We had negative revisions of 19 Bcfe and we developed approximately 19 Bcfe, or 7% of our total proved undeveloped reserves booked as of December 31, 2010 through the drilling of five gross (three net) development wells at an aggregate capital cost of approximately $24 million. Of the proved undeveloped reserves in our December 31, 2011 reserve report, none have remained undeveloped for more than five years since the date of initial booking as proved undeveloped reserves and none are scheduled for commencement of development on a date more than five years from the date the reserves were initially booked as proved undeveloped.

Productive Wells

The following table sets forth the number of productive wells in which we maintain ownership interests as of December 31, 2011:

	Oil		Natural Gas		Total	
	Gross (1)	**Net (2)**	**Gross (1)**	**Net (2)**	**Gross (1)**	**Net (2)**
South Texas	24	16			24	16
East Texas	2	1	248	235	250	236
Northwest Louisiana			107	45	107	45
Other	8	3	12		20	3
Total Productive Wells	34	20	367	280	401	300

(1) Royalty and overriding interest wells that have immaterial values are excluded from the above table. As of December 31, 2011, only three wells with royalty-only and overriding interests-only are included.
(2) Net working interest.

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Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. A gross well is a well in which we maintain an ownership interest, while a net well is deemed to exist when the sum of the fractional working interests owned by us equals one. Wells that are completed in more than one producing horizon are counted as one well. Of the gross wells reported above, 72 wells had completions in multiple producing horizons.

Acreage

The following table summarizes our gross and net developed and undeveloped acreage under lease as of December 31, 2011. Acreage in which our interest is limited to a royalty or overriding royalty interest is excluded from the table.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
South Texas	4,575	3,215	50,169	35,510	54,744	38,725
East Texas	88,931	57,788	37,983	25,508	126,914	83,296
Northwest Louisiana	39,827	22,746	3,025	1,752	42,852	24,498
Southeast Louisiana			25,674	25,589	25,674	25,589
Southwest Mississippi			76,126	54,624	76,126	54,624
Other	1,920	19			1,920	19
Total	135,253	83,768	192,977	142,983	328,230	226,751

Undeveloped acreage is considered to be those lease acres on which wells have not been drilled or completed to the extent that would permit the production of commercial quantities of natural gas or oil, regardless of whether or not such acreage contains proved reserves. As is customary in the oil and natural gas industry, we can retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the remaining primary term of such a lease. The oil and natural gas leases in which we have an interest are for varying primary terms; however, most of our developed lease acreage is beyond the primary term and is held so long as natural gas or oil is produced.

Lease Expirations

Our undeveloped lease acreage, including optioned acreage, will expire during the next four years, unless the leases are converted into producing units or extended prior to lease expiration.

The following table sets forth the lease expirations as of December 31, 2011:

Year	Acreage
2012(1)	19,430
2013	17,645
2014	10,719

2015	2,437

(1) In February 2012 we extended our Tuscaloosa Marine Shale leases that were to expire in 2012 for three years. We intend to retain our Angelina River Trend acreage that has 2012 lease expirations by perpetuating the leases through a continuous drilling provision.

Operator Activities

We operate a majority of our producing properties by value, and will generally seek to become the operator of record on properties we drill or acquire. Chesapeake Energy Corporation (Chesapeake) continues to operate our jointly-owned Northwest Louisiana acreage.

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Drilling Activities

The following table sets forth our drilling activities for the last three years. As denoted in the following table, gross wells refer to wells in which a working interest is owned, while a net well is deemed to exist when the sum of the fractional working interests we own in gross wells equals one.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	46	24.1	44	18.9	43	23.6
Non-Productive						
Total	46	24.1	44	18.9	43	23.6
Exploratory Wells:						
Productive	1	0.7	3	2.3	2	1.0
Non-Productive						
Total	1	0.7	3	2.3	2	1.0
Total Wells:						
Productive	47	24.8	47	21.2	45	24.6
Non-Productive						
Total	47	24.8	47	21.2	45	24.6

At December 31, 2011, the Company had six gross (three net) development wells and one exploration well with a minor working interest in process of being drilled.

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Net Production, Unit Prices and Costs

The following table presents certain information with respect to oil and natural gas production attributable to our interests in all of our properties (including each of the two fields which have attributed more than 15% of our total proved reserves as of December 31, 2011), the revenue derived from the sale of such production, average sales prices received and average production costs during each of the years in the three-year period ended December 31, 2011.

	Sales Volumes			Average Sales Prices (1)			Average
	Natural Gas Mmcf	Oil & Condensate MBbls	Total Mmcfe	Natural Gas Mcf	Oil & Condensate Per Bbl	Total Per Mcfe	Production Cost (2) Per Mcfe
For Year 2011							
Haynesville Shale Trend	24,753	1	24,760	$ 3.57	$ 94.80	$ 3.57	$ 0.18
Cotton Valley Taylor Sand	5,008	104	5,634	4.43	93.38	5.74	0.21
Eagle Ford Shale Trend	838	464	3,624	5.16	90.22	12.89	0.76
Other	5,568	75	6,011	4.80	94.60	5.69	2.11
Total	36,167	644	40,029	$ 3.92	$ 91.34	$ 5.01	$ 0.54
For Year 2010							
Haynesville Shale Trend	17,295	1	17,300	$ 3.83	$ 64.00	$ 3.83	$ 0.15
Cotton Valley Taylor Sand	2,386	24	2,529	4.38	62.17	4.72	0.16
Eagle Ford Shale Trend	131	39	368	3.53	68.26	8.49	0.62
Other	13,003	86	13,519	4.56	84.53	4.93	1.70
Total	32,815	150	33,716	$ 4.16	$ 76.59	$ 4.39	$ 0.78
For Year 2009							
Haynesville Shale Trend	7,960	1	7,966	$ 2.13	$ 55.00	$ 2.14	$ 0.19
Cotton Valley Taylor Sand	926	3	945	2.68	54.33	2.79	0.18
Eagle Ford Shale Trend							
Other	20,005	147	20,885	4.16	53.63	4.37	1.37
Total	28,891	151	29,796	$ 3.55	$ 53.65	$ 3.72	$ 1.01

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

In addition, two of our fields, the Bethany Longstreet and Beckville fields each account for more than 15% of our estimated proved reserves as of December 31, 2011. The table below provides production volume data for each of the fields for the years presented:

	Natural Gas (Mmcf)	Sales volumes Oil & Condensate (MBbls)	Total (Mmcfe)
For Year 2011			
Bethany Longstreet	14,962		14,962

Beckville	4,372	30	4,551
For Year 2010			
Bethany Longstreet	10,398	2	10,412
Beckville	6,259	37	6,483
For Year 2009			
Bethany Longstreet	6,538	5	6,567
Beckville	4,946	47	5,225

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For a discussion of comparative changes in our sales volumes, revenues and operating expenses for the three years ended December 31, 2011, see Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operations.

Oil and Natural Gas Marketing and Major Customers

Marketing. Our natural gas production is sold under spot or market-sensitive contracts to various gas purchasers on short-term contracts. Our oil production is sold to various purchasers under short-term rollover agreements based on current market prices.

Customers. Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. Revenues from the largest of these sources as a percent of oil and natural gas revenues for the year ended December 31, 2011 were as follows:

	2011
Shell Energy Resources LP	11%
Regency Field Services LLC	10%
Shell Trading (US) Company	9%

Competition

The oil and natural gas industry is highly competitive. Major and independent oil and natural gas companies, drilling and production acquisition programs and individual producers and operators are active bidders for desirable oil and natural gas properties, as well as the equipment and labor required to operate those properties. Many competitors have financial resources substantially greater than ours, and staffs and facilities substantially larger than us.

Employees

At February 10, 2012, we had 113 full-time employees in our two administrative offices and two field offices, none of whom is represented by any labor union. We regularly use the services of independent consultants and contractors to perform various professional services, particularly in the areas of construction, design, well-site supervision, permitting and environmental assessment. Independent contractors usually perform field and on-site production operation services for us, including gauging, maintenance, dispatching, inspection, and well testing.

Regulations

The availability of a ready market for any oil and natural gas production depends upon numerous factors beyond our control. These factors include regulation of oil and natural gas production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be shut-in because of an oversupply of natural gas or the lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies as well.

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Environmental and Occupational Health and Safety Matters

General

Our operations are subject to stringent and complex federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. Compliance with these laws and regulations may require the acquisition of permits before drilling or other related activity commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling and production activities on certain lands lying within wilderness, wetlands and other protected areas impose specific health and safety criteria addressing worker protection, and impose substantial liabilities for pollution arising from drilling and production operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that may limit or prohibit some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and, any changes in environmental laws and regulations that result in more stringent and costly well construction, drilling, waste management or completion activities or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business. While we believe that we are in substantial compliance with current applicable federal and state environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations or financial condition, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental laws to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended (CERCLA), also known as the Superfund law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or the sites where the release occurred, and companies that disposed or arranged for the disposal of hazardous substances released at the site. Under CERCLA, these persons may be subject to joint and several, strict liabilities for remediation costs at the site, natural resource damages and for the costs of certain health studies. Additionally, it is not uncommon for neighboring landowners and other third parties to file tort claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. We generate materials in the course of our operations that are regulated as hazardous substances.

We also may incur liability under the Resource Conservation and Recovery Act, as amended (RCRA), and comparable state statutes which impose stringent requirements related to the handling and disposal of hazardous wastes and non-hazardous solid wastes. While there exists an exclusion under RCRA from the definition of hazardous wastes for drilling fluids, produced waters and certain other wastes generated in the exploration, development or production of oil and natural gas, efforts have been made from time to time to remove this exclusion such that those wastes would be regulated as hazardous wastes and therefore subject to more rigorous RCRA standards. For instance, in September 2010, the

Natural Resources Defense Council filed a petition for rulemaking with the U.S. Environmental Protection Agency (EPA) requesting reconsideration of

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the continued application of this RCRA exclusion but, to date, the EPA has not taken any action on the petition. Notwithstanding the continued effectiveness of this RCRA exclusion, these exploration, development and production wastes remain subject to regulation by the EPA and state environmental agencies as non-hazardous solid wastes. We generate petroleum product wastes and ordinary industrial wastes that may be regulated as non-hazardous solid waste and hazardous wastes. The EPA and state agencies have imposed stringent requirements for the disposal of hazardous and solid wastes.

We currently own or lease, and in the past have owned or leased, properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes and petroleum hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties whose treatment and disposal of hazardous substances, wastes and petroleum hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges and Subsurface Injections

The Federal Water Pollution Control Act, as amended, (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 state and federal waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In addition, the Oil Pollution Act of 1990, as amended (OPA), imposes a variety of requirements related to the prevention of oil spills into navigable waters. OPA subjects owners of facilities to strict, joint and several liabilities for specified oil removal costs and certain other damages including natural reservoir damages arising from a spill.

The disposal of oil and natural gas wastes into underground injection wells are subject to the Safe Drinking Water Act, as amended, and analogous state laws. Under Part C of the Safe Drinking Water Act, the EPA established the Underground Injection Control Program, which establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Louisiana and Texas, where we

operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nevertheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws, regulate emissions of various air pollutants from many sources in the United States, including crude oil and natural gas production activities. These laws and any implementing regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, on July 28, 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production, including, among other things, the application of reduced emission completion techniques, referred to as green completions, for completion of newly drilled and fractured wells in addition to establishing specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. Final action on the proposed rules is expected no later than April 3, 2012. We do not believe that these requirements, if adopted, would have a material adverse effect on our operations.

Climate Change Based on findings by the EPA in December 2009 that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the CAA that require a reduction in emissions of GHGs from motor vehicles and also construction and operating permit review for GHG emissions from certain large stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) construction and Title V operating permit programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore and offshore oil and natural gas production facilities, which may include certain of our operations, on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

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In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production interests and operations.

Endangered Species

The federal Endangered Species Act, as amended, and analogous state laws restrict activities that could have an adverse effect on threatened or endangered species or their habitats. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing more than 250 species as endangered or threatened under the ESA over the next six years, through the agency s 2017 fiscal year. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety

We are also subject to the requirements of the federal Occupational Safety and Health Act , as amended, (OSHA); and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act, as amended, and implementing regulations and similar state statutes and regulations, requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws relating to worker health and safety.

Other Laws and Regulations

State statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. In addition, there are state statutes, rules and regulations governing conservation matters, including the unitization or pooling of oil and natural gas properties, establishment of maximum rates of production from oil and natural gas wells and the spacing, plugging and abandonment of such wells. Such statutes and regulations may limit the rate at which oil and natural gas could otherwise be produced from our properties and may restrict the number of wells that may be drilled on a particular lease or in a particular field.

Item 1A. ***Risk Factors***

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

The Company has made in this report, and may from time to time otherwise make in other public filings, press releases and discussions with Company management, forward-looking statements within the meaning of

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Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 concerning the Company s operations, economic performance and financial condition. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and natural gas properties, marketing and midstream activities, and also include those statements accompanied by or that otherwise include the words may, could, believes, expects, anticipates, intends, estimates, projects, predicts, target, goal, plans, objective, potential, should, or similar expressions or variations on such expressions that convey the uncertainty of future events or outcomes. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. The Company has based these forward-looking statements on its current expectations and assumptions about future events. These statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to be correct. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made; the Company undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company s expectations include, but are not limited to, the following risk and uncertainties:

- *planned capital expenditures;*
- *future drilling activity;*
- *our financial condition;*
- *business strategy including the Company s ability to successfully transition to more liquids-focused operations;*
- *the market prices of oil and natural gas;*
- *uncertainties about the estimated quantities of oil and natural gas reserves;*
- *financial market conditions and availability of capital;*
- *production;*
- *hedging arrangements;*
- *future cash flows and borrowings;*
- *litigation matters;*

pursuit of potential future acquisition opportunities;

sources of funding for exploration and development;

general economic conditions, either nationally or in the jurisdictions in which the Company or its subsidiary is doing business;

legislative or regulatory changes, including retroactive royalty or production tax regimes, *hydraulic-fracturing regulation, drilling and permitting regulations, derivatives reform, changes in state and federal corporate taxes, environmental regulation, environmental risks and liability under federal, state and foreign and local environmental laws and regulations;*

the creditworthiness of the Company s financial counterparties and operation partners;

the securities, capital or credit markets;

the Company s ability to repay its debt; and

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other factors discussed below and elsewhere in this Annual Report on Form 10-K and in the Company s other public filings, press releases and discussions with Company management.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve report. These differences may be material.

The proved oil and natural gas reserve information included in this report are estimates. These estimates are based on reports prepared by NSAI, our independent reserve engineers, and were calculated using the unweighted average of first-day-of-the-month oil and natural gas prices in 2011. These prices will change and may be lower at the time of production than those prices that prevailed during 2011. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing wells;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and natural gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

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

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material. The discounted future net cash flows included in this document should not be considered as the current market value of the estimated oil and natural gas reserves attributable to our properties. As required by the SEC, the standardized measure of discounted future net cash flows from proved reserves are generally based on 12-month average prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and natural gas;
- increases or decreases in consumption; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which is required by the SEC to be used to calculate discounted future net cash flows for reporting purposes, and which we use in calculating our PV-10, is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Our operations are subject to governmental risks that may impact our operations.

Our operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, state, tribal, local and other laws and regulations such as restrictions on production, permitting and changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies or price gathering-rate controls. 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, tribal 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, including tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

The adoption of financial reform legislation by the United States Congress in 2010 could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity prices, interest rates and other risks associated with our business.

In 2010, the United States Congress adopted comprehensive financial reform legislation that changes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was signed into law by the President on July 21, 2010, and requires the Commodity Futures Trading Commission, or the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC and the SEC have not completed all the rulemaking the Dodd-Frank Act directs them to carry out. The regulators have granted temporary relief from the general effective date for various requirements of the Dodd-Frank Act, and also have indicated they may phase in implementation of many of its requirements. The CFTC has proposed regulations under the Dodd-Frank Act to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. The CFTC adopted these proposed regulations with modifications on October 18, 2011, but it is not possible at this time to predict when these regulations will become effective. The CFTC and other regulators have proposed regulations that would specify new margin requirements and clearing and trade-execution requirements in connection with certain derivative activities. It is not clear what the final regulations will provide. The legislation and new regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The new legislation and any new regulations could significantly increase the cost of some derivative contracts (including through requirements to post collateral, or providing other credit support which could adversely affect our available liquidity), materially alter the terms of some derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the new legislation and new regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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

Legislation has been proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our common stock.

Our operations are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations, or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations including the acquisition of permits, including drilling permits, before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, or waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

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

In response to findings made by the EPA in December 2009 that emissions of carbon dioxide, methane, and other greenhouse gases (GHGs) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that require a reduction in emissions of GHGs from motor vehicles and also require certain Prevention of Significant Deterioration (PSD) and

Title V permit

requirements for GHG emissions from certain large stationary sources. The EPA rules have tailored the PSD and Title V permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore and offshore oil and natural gas production facilities, which may include certain of our operations, on an annual basis. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely demand for the oil and natural gas we produce.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Louisiana and Texas, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Our future revenues are dependent on the ability to successfully complete drilling activity.

Drilling and exploration are the main methods we utilize to replace our reserves. However, drilling and exploration operations may not result in any increases in reserves for various reasons. Exploration activities

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involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- lack of acceptable prospective acreage;
- inadequate capital resources;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- unavailability or high cost of drilling rigs, equipment or labor;
- reductions in oil and natural gas prices;
- limitations in the market for oil and natural gas;
- title problems;
- compliance with governmental regulations;
- mechanical difficulties; and
- risks associated with horizontal drilling.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain.

In addition, while lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically, higher oil and natural gas prices generally increase the demand for drilling rigs, equipment and crews and can lead to shortages of, and increased costs for, such drilling equipment, services and personnel. Such shortages could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could adversely affect our ability to increase our reserves and production and reduce our revenues.

Oil and natural gas prices are volatile; a sustained decrease in the price of oil or natural gas would adversely impact our business.

Our success will depend on the market prices of oil and natural gas. These market prices tend to fluctuate significantly in response to factors beyond our control. The prices we receive for our crude oil production are based on global market conditions. The general pace of global economic growth, the continued instability in the Middle East and other oil and natural gas producing regions and actions of the Organization of Petroleum Exporting Countries and its maintenance of production constraints, as well as other economic, political, and environmental factors will continue to affect world supply and prices. Domestic natural gas prices fluctuate significantly in response to numerous factors including U.S. economic conditions, weather patterns, other factors affecting demand such as substitute fuels, the impact of drilling levels on crude oil and natural gas supply, and the environmental and access issues that limit future drilling activities for the industry.

Natural gas and crude oil prices are extremely volatile. Average oil and natural gas prices varied substantially during the past few years. Any actual or anticipated reduction in natural gas and crude oil and prices may further depress the level of exploration, drilling and production activity. We expect that commodity prices will continue to fluctuate significantly in the future.

Changes in commodity prices significantly affect our capital resources, liquidity and expected operating results. Realized prices for natural gas decreased slightly in 2011 and are lower when compared with average prices in prior years. These lower prices, coupled with the slow recovery in financial markets that has significantly limited and increased the cost of capital, have compelled most oil and natural gas producers, including us, to reduce the level of exploration, drilling and production activity. This will have a significant effect on our capital resources, liquidity and expected operating results. Any sustained reductions in oil and natural gas prices will directly affect our revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Further reductions in oil and natural gas prices could also reduce the quantities of reserves that are commercially recoverable. A reduction in our reserves could have other adverse consequences including a possible downward redetermination of the availability of borrowings under our senior credit facility, which would restrict our liquidity. Additionally, further or continued declines in prices could result in non-cash charges to earnings due to impairment write downs. Any such writedown could have a material adverse effect on our results of operations in the period taken.

Our use of oil and natural gas price hedging contracts may limit future revenues from price increases and result in significant fluctuations in our net income.

We use hedging transactions with respect to a portion of our oil and natural gas production to achieve more predictable cash flow and to reduce our exposure to price fluctuations. While the use of hedging transactions limits the downside risk of price declines, their use may also limit future revenues from price increases. We hedged approximately 43% (40% of gas production was hedged and 66% of oil production was hedged) of our total production volumes for the year ended December 31, 2011.

Our results of operations may be negatively impacted by our commodity derivative instruments and fixed price forward sales contracts in the future and these instruments may limit any benefit we would receive from increases in the prices for oil and natural gas.

		December 31,	
Oil and Natural Gas Derivatives (in thousands)	**2011**	**2010**	**2009**
Realized gain on oil and natural gas derivatives	$ 31,305	$ 24,590	$ 97,957
Unrealized gain on oil and natural gas derivatives	3,234	30,706	(50,151)
Total gain on oil and natural gas derivatives	$ 34,539	$ 55,296	$ 47,806

We account for our oil and natural gas derivatives using fair value accounting standards. Each derivative is recorded on the balance sheet as an asset or liability at its fair value. Additionally, changes in a derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met at the time the derivative contract is executed. We have elected not to apply hedge accounting treatment to our swaps and collars and, as such, all changes in the fair value of these instruments are recognized in earnings. Our fixed price physical contracts qualify for the normal purchase and normal sale exception. Contracts that qualify for this treatment do not require mark-to-market accounting treatment.

In the future, we will be exposed to volatility in earnings resulting from changes in the fair value of our derivative instruments. See *Note 8 Derivative Activities in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Because our operations require significant capital expenditures, we may not have the funds available to replace reserves, maintain production or maintain interests in our properties.

We must make a substantial amount of capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. Historically, we have paid for these expenditures with cash from operating activities, proceeds from debt and equity financings and asset sales. Our revenues or cash flows could be reduced because of lower oil and natural gas prices or for other reasons. If our revenues or cash flows decrease, we may not have the funds available to replace reserves or maintain production at current levels. If this occurs, our production will decline over time. Other sources of financing may not be available to us if our cash flows from operations are not sufficient to fund our capital expenditure requirements. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. If funding is not available as needed, or is available only on more expensive or otherwise unfavorable terms, we may be unable to meet our obligations as they come due or we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. Where we are not the majority owner or operator of an oil and natural gas property, we may have no control over the timing or amount of capital expenditures associated with the particular property. If we cannot fund such capital expenditures, our interests in some properties may be reduced or forfeited.

If we are unable to replace reserves, we may not be able to sustain production at present levels.

Our future success depends largely upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Unless we replace the reserves we produce through successful development, exploration or acquisition activities, our proved reserves will decline over time. In addition, approximately 58% of our total estimated proved reserves by volume at December 31, 2011, were undeveloped. By their nature, estimates of proved undeveloped reserves and timing of their production are less certain particularly because we may chose not to develop such reserves on anticipated schedules in future adverse oil or natural gas price environments. Recovery of such reserves will require significant capital expenditures and successful drilling operations. The lack of availability of sufficient capital to fund such future operations could materially hinder or delay our replacement of produced reserves. We may not be able to successfully find and produce reserves economically in the future. In addition, we may not be able to acquire proved reserves at acceptable costs.

We may incur substantial impairment writedowns.

If management s estimates of the recoverable proved reserves on a property are revised downward or if oil and natural gas prices decline, we may be required to record additional non-cash impairment writedowns in the future, which would result in a negative impact to our financial position. Furthermore, any sustained decline in oil and natural gas prices may require us to make further impairments. We review our proved oil and natural gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management s estimates of future oil and natural gas prices to the estimated future production of oil and natural gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units estimated reserves, future cash flows and fair value. For the years ended December 31, 2011, 2010 and 2009, we recorded impairments related to oil and natural gas properties of $8.1 million, $234.9 million and $208.9 million, respectively.

Management s assumptions used in calculating oil and natural gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property s fair value.

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Additionally, as management s views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Essentially all of our estimated proved reserves at December 31, 2011, and all our production during 2011 were associated with our Northwest Louisiana, East Texas and South Texas properties which include the Haynesville Shale, Cotton Valley Taylor Sand and Eagle Ford Shale, respectfully. Accordingly, if the level of production from these properties substantially declines or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention (including potential regulation or limitation of the use of high pressure fracture stimulation techniques in these formations) or natural disasters, it could have a material adverse effect on our overall production level and our revenue.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. For example, Chesapeake operates certain properties in the Haynesville Shale. We have less ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them versus those fields in which we are the operator. Our dependence on the operator and other working interest owners for these projects and our reduced influence or ability to control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital and lead to unexpected future costs.

Our ability to sell natural gas and receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints and various transportation interruptions.

We operate primarily in the Northwest Louisiana, East Texas and South Texas areas. Our Haynesville Shale acreage is located in Northwest Louisiana and East Texas. A number of companies are currently operating in the Haynesville Shale. If drilling in the Haynesville Shale and Eagle Ford Shale continues to be successful, the amount of natural gas being produced could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in this region. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for Northwest Louisiana and East Texas may not occur or may be substantially delayed for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our natural gas to interstate pipelines. In such an event, we might have to shut in our wells awaiting a pipeline connection or capacity or sell natural gas production at significantly lower prices than those quoted on New York Mercantile Exchange (NYMEX) or that we currently project, which would adversely affect our results of operations.

A portion of our oil and natural gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

Our debt instruments impose restrictions on us that may affect our ability to successfully operate our business.

Our Senior Credit Facility contains customary restrictions, including covenants limiting our ability to incur additional debt, grant liens, make investments, consolidate, merge or acquire other businesses, sell assets, pay dividends and other distributions and enter into transactions with affiliates. We also are required to meet specified financial ratios under the terms of our senior credit facility. As of December 31, 2011, we were in compliance with all the financial covenants of our Senior Credit Facility. These restrictions may make it difficult for us to successfully execute our business strategy or to compete in our industry with companies not similarly restricted. The Senior Credit Facility matures on July 1, 2014 (subject to automatic extension to February 25, 2016, if, prior to maturity, we prepay or escrow certain proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029. Any replacement credit facility may have more restrictive covenants or provide us with less borrowing capacity.

We may be unable to identify liabilities associated with the properties that we acquire or obtain protection from sellers against them.

The acquisition of properties requires us to assess a number of factors, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well, platform or pipeline. We cannot necessarily observe structural and environmental problems, such as pipeline corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities relating to the acquired assets and indemnities are unlikely to cover liabilities relating to the time periods after closing. We may be required to assume any risk relating to the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations. The incurrence of an unexpected liability could have a material adverse effect on our financial position and results of operations.

Competition in the oil and natural gas industry is intense, and we are smaller and have a more limited operating history than some of our competitors.

We compete with major and independent oil and natural gas companies for property acquisitions. We also compete for the equipment and labor required to operate and to develop these properties. Some of our competitors have substantially greater financial and other resources than us. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for oil and natural gas properties and may be able to define, evaluate, bid for and acquire a greater number of properties than we can. Our ability to acquire additional properties and develop new and existing properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Our success depends on our management team and other key personnel, the loss of any of whom could disrupt our business operations.

Our success will depend on our ability to retain and attract experienced engineers, geoscientists and other professional staff. We depend to a large extent on the efforts, technical expertise and continued employment of these personnel and members of our management team. If a significant number of them resign or become unable to continue in their present role and if they are not adequately replaced, our business operations could be adversely affected.

The oil and natural gas business involves many uncertainties, economic risks and operating risks that can prevent us from realizing profits and can cause substantial losses.

The nature of the oil and natural gas business involves certain operating hazards such as:

well blowouts;

cratering;

- explosions;
- uncontrollable flows of oil, natural gas, brine or well fluids;
- fires;
- formations with abnormal pressures;
- shortages of, or delays in, obtaining water for hydraulic fracturing operations;
- environmental hazards such crude oil spills;
- natural gas leaks;
- pipeline and tank ruptures;
- discharges of brine, well stimulation and completion fluids or toxic gases into the environment;
- pollution;
- other hazards and risks;

Any of these operating hazards could result in substantial losses to us. As a result, substantial liabilities to third parties or governmental entities may be incurred. The payment of these amounts could reduce or eliminate the funds available for exploration, development or acquisitions. These reductions in funds could result in a loss of our properties. Additionally, some of our oil and natural gas operations are located in areas that are subject to weather disturbances such as hurricanes. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;

bodily injury;

third party property damage;

medical expenses;

legal defense costs;

pollution in some cases;

well blowouts in some cases and

workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

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

None.

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Item 3. ***Legal Proceedings***

A discussion of current legal proceedings is set forth in *Note 9 Commitments and Contingencies in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Item 4B. ***Mine Safety Disclosure***

Not Applicable.

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PART II

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

Market Price of Our Common Stock

Our common stock is traded on the New York Stock Exchange under the symbol GDP .

At February 10, 2012, the number of holders of record of our common stock without determination of the number of individual participants in security positions was 1,298 and 36,369,685 shares outstanding. High and low sales prices for our common stock for each quarter during 2011 and 2010 were as follows:

	2011		2010	
	High	**Low**	**High**	**Low**
First Quarter	$ 23.04	$ 18.17	$ 25.83	$ 15.52
Second Quarter	22.47	17.54	19.19	11.26
Third Quarter	20.73	11.82	14.81	11.16
Fourth Quarter	17.52	10.77	17.71	12.51

Dividends

We have neither declared nor paid any cash dividends on our common stock and do not anticipate declaring any dividends 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, our senior bank credit facility contains restrictions on the payment of dividends to the holders of common stock. For additional information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Issuer Repurchases of Equity Securities

We made no open market repurchases of our common stock for the year ended December 31, 2011. When an employee s restricted stock shares vest, the company (at the option of the employee) generally withholds an amount of shares necessary to cover that employees minimum payroll tax withholding obligation. The company then remits the withholding amount to the appropriate tax authority and subsequently retires the shares. During 2011, we withheld 84,911 shares of common stock from issuance in this manner and paid $1.4 million to the appropriate tax authority as minimum withholding.

For information on securities authorized for issuance under our equity compensation plans, see Item 12. Security Ownership of Certain Beneficial Owners and Management.

Performance

The following performance graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the company specifically incorporates it by reference into such filing.

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The following graph compares the cumulative five-year total return to stockholders on our common stock relative to the cumulative total returns of the S&P 500 Index and the S&P Small-Cap Index. An investment of $100 is assumed to have been made in the Company s common stock and the indexes on December 31, 2006 and its relative performance is tracked through December 31, 2011.

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Item 6. ***Selected Financial Data***

The following table sets forth our selected financial data and other operating information. The selected consolidated financial data in the table are derived from our consolidated financial statements. This data should be read in conjunction with the consolidated financial statements, related notes and other financial information included herein.

	Summary Financial Information				
	2011	**2010**	**2009**	**2008**	**2007**
	(In thousands, except per share amounts)				
Revenues:					
Oil and natural gas revenues	$ 200,456	$ 148,031	$ 110,784	$ 215,369	$ 110,691
Other	613	302	(358)	682	614
	201,069	148,333	110,426	216,051	111,305
Operating Expenses:					
Lease operating expense	21,490	26,306	30,188	31,950	22,465
Production and other taxes	5,450	3,627	4,317	7,542	2,272
Transportation	12,974	9,856	9,459	8,645	5,964
Depreciation, depletion and amortization	131,811	105,913	160,361	107,123	79,766
Exploration	8,289	10,152	9,292	8,404	7,346
Impairment	8,111	234,887	208,905	28,582	7,696
General and administrative	29,799	30,918	27,923	24,254	20,888
Loss (gain) on sale of assets	(236)	2,824	(297)	(145,876)	(42)
Other	448	4,268			109
	218,136	428,751	450,148	70,624	146,464
Operating income (loss)	(17,067)	(280,418)	(339,722)	145,427	(35,159)
Other income (expense):					
Interest expense	(49,351)	(37,179)	(26,148)	(22,410)	(17,878)
Interest income and other	59	117	458	1,682	11,469
Gain (loss) on derivatives not designated as hedges	34,539	55,275	47,115	51,547	(6,439)
Gain on early extinguishment of debt	62				
	(14,691)	18,213	21,425	30,819	(12,848)
Income (loss) before income taxes	(31,758)	(262,205)	(318,297)	176,246	(48,007)
Income tax (expense) benefit		85	67,311	(54,472)	9,294
Net income (loss)	(31,758)	(262,120)	(250,986)	121,774	(38,713)
Preferred stock dividends	6,047	6,047	6,047	6,047	6,047
Net income (loss) applicable to common stock	$ (37,805)	$ (268,167)	$ (257,033)	$ 115,727	$ (44,760)
PER COMMON SHARE					
Net income (loss) applicable to common stock basic	$ (1.05)	$ (7.47)	$ (7.17)	$ 3.42	$ (1.75)
Net income (loss) applicable to common stock diluted	$ (1.05)	$ (7.47)	$ (7.17)	$ 3.23	$ (1.75)
Weighted average common shares outstanding basic	36,124	35,921	35,866	33,806	25,578
Weighted average common shares outstanding diluted	36,124	35,921	35,866	40,397	25,578
Balance Sheet Data:					

Total assets	$ 862,103	$ 664,577	$ 860,274	$ 1,038,287	$ 589,233
Total long-term debt	566,126	179,171	330,147	226,723	185,449
Stockholders equity	143,700	183,972	445,385	665,348	312,781

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

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Annual Report on Form 10-K in Item 8, and the information set forth in *Risk Factors* under Item 1A.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of properties primarily in Northwest Louisiana and East Texas, which includes the Haynesville Shale and Cotton Valley Taylor Sand, and South Texas which includes the Eagle Ford Shale Trend.

We seek to increase shareholder value by growing our oil and natural gas reserves, production revenues and operating cash flow. In our opinion, on a long term basis, growth in oil and natural gas reserves and production on a cost-effective basis are the most important indicators of performance success for an independent oil and natural gas company.

Management strives to increase our oil and natural gas reserves, production and cash flow through exploration and development activities. We develop an annual capital expenditure budget which is reviewed and approved by our board of directors on a quarterly basis and revised throughout the year as circumstances warrant. We take into consideration our projected operating cash flow and externally available sources of financing, such as bank debt, when establishing our capital expenditure budget.

We place primary emphasis on our internally generated operating cash flow in managing our business. For this purpose, operating cash flow is defined as cash flow from operating activities as reflected in our Statement of Cash Flows. Management considers operating cash flow a more important indicator of our financial success than other traditional performance measures such as net income because operating cash flow considers only the cash expenses incurred during the period and excludes the non-cash impact of unrealized hedging gains (losses) and impairments.

Our revenues and operating cash flow depend on the successful development of our inventory of capital projects with available capital, the volume and timing of our production, as well as commodity prices for oil and natural gas. Such pricing factors are largely beyond our control, however, we employ commodity hedging techniques in an attempt to minimize the volatility of short term commodity price fluctuations on our earnings and operating cash flow.

Business Strategy

Our business strategy is to provide long term growth in reserves on a cost-effective basis. We focus on adding reserve value through the development of our Haynesville Shale, Cotton Valley Taylor Sand and Eagle Ford Shale Trend acreage and the timely development of our large relatively low risk development program in the Northwest Louisiana, East Texas and South Texas area. We regularly evaluate possible acquisitions of prospective acreage and oil and natural gas drilling opportunities.

Several of the key elements of our business strategy are the following:

Develop existing property base. We seek to maximize the value of our existing assets by developing and exploiting our properties with the highest rate of return on our capital expenditures. We intend to concentrate on developing our multi-year inventory of drilling locations on our acreage in the Eagle Ford Shale Trend, Haynesville Shale, Cotton Valley Taylor Sand and Tuscaloosa Marine Shale in order to develop our oil and natural gas reserves. We estimate that our Eagle Ford Shale Trend acreage currently includes approximately 500 gross unrisked, non-proved drilling locations. Our Haynesville Shale acreage currently includes approximately 1,165 gross unrisked, non-proved drilling locations based on anticipated well spacing.

Increase our oil production. During the past year, we have concentrated on increasing our crude oil production and reserves by investing and drilling in the Eagle Ford Shale Trend. We intend to take advantage of the current favorable sales price of oil compared to the relative sales price of natural gas. We increased our oil production as a percentage of total production from 3% in 2010 to 10% in 2011.

Expand acreage position in shale plays. As of December 31, 2011, we have acquired approximately 80,200 net acres in the Tuscaloosa Marine Shale Trend in Southeastern Louisiana and Southwestern Mississippi. We continue to concentrate our efforts in areas where we can apply our technical expertise and where we have significant operational control or experience. To leverage our extensive regional knowledge base, we seek to acquire leasehold acreage with significant drilling potential in areas that exhibit similar characteristics to our existing properties. We continually strive to rationalize our portfolio of properties by selling marginal non-core properties in an effort to redeploy capital to exploitation, development and exploration projects that offer a potentially higher overall return.

Focus on maximizing cash flow margins. We intend to maximize operating cash flow by focusing on higher-margin oil development in the Eagle Ford Shale Trend and lowering our overall operating costs in our natural gas properties. In the current commodity price environment, our Eagle Ford Shale Trend assets offer more attractive cash flow margins than our natural gas assets. From 2009 to 2011, we lowered our lease operating costs on a consolidated basis from $1.01 per Mcfe to $0.54 per Mcfe by focusing on lower cost Haynesville Shale wells and divesting higher cost mature assets. We expect this trend to continue as it relates to our natural gas properties.

Maintain financial flexibility. As of December 31, 2011, we had a borrowing base of $275 million under our $600 million Senior Credit Facility, of which $102.5 million was outstanding. We have historically funded growth through cash flow from operations, debt, equity and equity-linked security issuances, divestments of non-core assets and strategic joint ventures. We actively manage our exposure to commodity price fluctuations by hedging meaningful portions of our expected production through the use of derivatives, including fixed price swaps, swaptions and costless collars. The level of our hedging activity and the duration of the instruments employed depend upon our view of market conditions, available hedge prices and our operating strategy.

2011 Overview

We achieved annual production volume growth of 19% with production volume growing from 33.7 Bcfe in 2010 to 40.0 Bcfe in 2011.

We increased our proved reserves by 8% compared to 2010, ending the year with estimated proved reserves of approximately 501.0 Bcfe (approximately 463.5 Bcf of natural gas, 0.5 MMBbls of NGL and 5.8 MMBbls of oil and condensate), with a PV-10 of $454 million and a standardized measure of $450 million, approximately 42% of which is proved developed.

We drilled 20 gross (14 net wells), in the Eagle Ford Shale Trend and added 18 wells to production in 2011.

We drilled 19 gross (five net) wells in the Haynesville Shale Trend and added 22 gross (six net) wells to production in 2011. As of December 31, 2011, we had four gross (two net) drilling wells in progress and six (two net) wells drilled but awaiting completion in the Haynesville Shale Trend.

We reduced our lease operating expense per Mcfe by 31% from $0.78 in 2010 to $0.54 per Mcfe in 2011.

We acquired approximately 80,200 net acres in the Tuscaloosa Marine Shale Trend in Southeastern Louisiana and Southwestern Mississippi as of December 31, 2011.

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Eagle Ford Shale Trend

During 2011, we continued drilling operations on our acreage in the Eagle Ford Shale Trend. We entered into the Eagle Ford Shale Trend in April 2010. Our leasehold position is located in both La Salle and Frio counties, Texas. We hold approximately 54,700 gross (38,700 net) acres as of December 31, 2011, all of which are either producing from or prospective for the Eagle Ford Shale Trend. During 2011, we conducted drilling operations on approximately 20 gross (14 net) Eagle Ford Shale Trend wells. In 2012, we plan to spend approximately $175 million representing, 70% of our 2012 capital budget, on 31 gross (21 net) wells in the Eagle Ford Shale Trend.

Tuscaloosa Marine Shale Trend

During 2011, we acquired approximately 101,800 gross (80,200 net) acres in the Tuscaloosa Marine Shale Trend, an emerging oil shale play in East Feliciana, West Feliciana, St Helena and Washington Parishes in Southeastern Louisiana and Wilkinson, Pike and Amite counties in Southwestern Mississippi. In December 2011, we participated in our first non-operated well in the Tuscaloosa Marine Shale. We anticipate participating in several low interest, wells in 2012 and begin our operated activity in the second quarter of 2012. In 2012, we plan to spend approximately $20 $45 million in the Tuscaloosa Marine Shale Trend.

Haynesville Shale Trend

Our relatively low risk development drilling program in this trend is primarily centered in and around Rusk, Panola, Angelina and Nacogdoches counties, Texas and DeSoto and Caddo parishes, Louisiana. We hold approximately 127,000 gross (83,300 net) acres as of December 31, 2011 producing from and prospective for the Haynesville Shale. As of year-end 2011, we drilled and completed a cumulative total of 89 gross (37 net) wells in the trend with a 100% success rate. Our net production volumes from our Haynesville Shale wells aggregated approximately 67,835 Mcfe per day in 2011, or approximately 62% of our total oil and natural gas production for the year. Our 2012 capital expenditure budget includes plans to utilize one rig to conduct drilling operations on two gross (two net) Haynesville Shale horizontal wells.

Core Haynesville Shale

Our core Haynesville Shale drilling program is primarily concentrated in the Bethany-Longstreet and Greenwood-Waskom fields in Caddo and DeSoto Parishes in Northwest Louisiana. Our core Haynesville Shale drilling activity includes both operated and non-operated drilling in and around our core acreage positions in Northwest Louisiana. We currently hold approximately 31,500 gross (15,600 net) acres as of December 31, 2011. Our net production volumes from our core Haynesville Shale wells totaled approximately 52,805 Mcfe per day in 2011, or approximately 48% of our total production for the year. In 2012, we estimate that we will spend approximately $15 million primarily on carryover wells in our core Haynesville Shale area.

Shelby Trough / Angelina River Trend

During the second half of 2010, we spud our first Haynesville & Bossier Shale wells in the Shelby Trough / Angelina River Trend area. We operate all of our drilling activities in this area, which is primarily located in Nacogdoches, Angelina and Shelby counties, Texas. The Company currently holds approximately 42,000 gross (29,800 net) acres as of December 31, 2011. Our net production volumes from our Shelby Trough wells totaled approximately 9,523 Mcfe per day in 2011, or approximately 9% of our total production for the year. In 2012, we estimate that we will spend approximately $20 million on two gross wells (including one carryover well) in the Shelby Trough/Angelina River Trend area.

Cotton Valley Taylor Sand

During 2011, we drilled four successful horizontal Cotton Valley Taylor Sand wells throughout our acreage position in the Minden, Beckville and South Henderson fields of East Texas. Our net production volumes from our Cotton Valley Taylor Sand wells totaled approximately 15,435 Mcfe per day in 2011, or approximately 14% of our total production for the year. During 2011, we completed and initiated production on five gross (five net) oil wells in the play.

Results of Operations

For the year ended December 31, 2011, we reported net loss applicable to common stock of $37.8 million, or $1.05 per share (basic and diluted), on operating revenues of $201.1 million. This compares to net loss applicable to common stock of $268.2 million, or $7.47 per share (basic and diluted), for the year ended December 31, 2010 and net loss applicable to common stock of $257.0 million, or $7.17 per share (basic and diluted) for the year ended December 31, 2009.

The following table reflects our summary operating information for the periods presented in thousands except for price and volume data.

	Year End December 31,				Year End December 31,			
Summary Operating Information:	**2011**	**2010**	**Variance**		**2010**	**2009**	**Variance**	
Revenues:								
Natural gas	$ 141,665	$ 136,527	$ 5,138	4%	$ 136,527	$ 102,692	$ 33,835	33%
Oil and condensate	58,791	11,504	47,287	411%	11,504	8,092	3,412	42%
Natural gas, oil and condensate	200,456	148,031	52,425	35%	148,031	110,784	37,247	34%
Operating revenues	201,069	148,333	52,736	36%	148,333	110,426	37,907	34%
Operating expenses	218,136	428,751	(210,615)	(49%)	428,751	450,148	(21,397)	(5%)
Operating loss	(17,067)	(280,418)	263,351	94%	(280,418)	(339,722)	59,304	17%
Net loss applicable to common stock	(37,805)	(268,167)	230,362	86%	(268,167)	(257,033)	(11,134)	4%
Net Production:								
Natural gas (Mmcf)	36,167	32,815	3,352	10%	32,815	28,891	3,924	14%
Oil and condensate (MBbls)	644	150	494	329%	150	151	(1)	(1%)
Total (Mmcfe)	40,029	33,716	6,313	19%	33,716	29,796	3,920	13%
Average daily production (Mcfe/d)	109,669	92,373	17,296	19%	92,373	81,632	10,741	13%
Average Realized Sales Price Per Unit:								
Natural gas (per Mcf)	$ 3.92	$ 4.16	$ (0.24)	(6%)	$ 4.16	$ 3.55	$ 0.61	17%
Oil and condensate (per Bbl)	91.34	76.59	14.75	19%	76.59	53.65	22.94	43%
Average realized price (per Mcfe)	5.01	4.39	0.62	14%	4.39	3.72	0.67	18%

Oil and Natural Gas Revenue

Oil and natural gas revenues increased in 2011 compared to 2010. The increase in average realized sales price compared to 2010 contributed approximately $20.8 million to the increase in oil and natural gas revenue while the net production increase compared to 2010 contributed approximately $31.6 million to the increase in oil and natural gas revenue. Our average realized sales price was $5.01 per Mcfe in 2011 compared to $4.39 per Mcfe in 2010. Sales prices are dictated by the market. We increased production by the continued development of our Haynesville Shale and Eagle Ford Shale Trend assets. The drilling of 27 wells in Northwest Louisiana and East Texas, 19 of which were in the Haynesville Shale, resulted in the continued trend of annual natural gas production growth for the Company. The drilling of 20 South Texas wells, all of which were in the Eagle Ford Shale Trend, increased our oil production.

For the year ended December 31, 2011, our average realized price for natural gas was $3.92 per Mcf. For the same period in 2010, our average realized price for natural gas was $4.16 per Mcf. For the year ended

December 31, 2011, our average realized price including the effect of the realized gains and losses on our natural gas derivatives was $4.70 per Mcf. For the same period in 2010, our average realized price including the effect of the realized gains and losses on our natural gas derivatives was $4.91 per Mcf. For the year ended December 31, 2011, our average realized price for oil was $91.34 per Bbl and our average realized price for oil including the effect of the realized gains and losses on our oil derivatives was $96.23 per Bbl. We did not have realized gains or losses on oil derivatives for the year ended December 31, 2010.

The difference between our average realized prices inclusive of the hedge realizations in the year ended December 31, 2011 and 2010 periods relates to our natural gas collars and basis swap contracts. During 2011, we had 40,000 MMBtus per day hedged at a floor price of $6.00 per MMBtu and during 2010 we had 50,000 MMBtus per day hedged at a floor price of $6.00 per MMBtu and 50,000 MMBtus per day hedged in our basis swaps.

Oil and natural gas revenues increased in 2010 compared to 2009. The increase in average sales price compared to 2009 contributed approximately $20.0 million to the increase in oil and natural gas revenue while the net production increase compared to 2009 contributed approximately $17.2 million to the increase in oil and natural gas revenue. Our average realized sales price was $4.39 per Mcfe in 2010 compared to $3.72 per Mcfe in 2009. Sales prices are dictated by the market. We increased production by the development of our Haynesville Shale assets. The drilling and completion of 40 wells in our Northwest Louisiana and East Texas properties, 36 of which were in the Haynesville Shale, resulted in annual natural gas production growth for the Company.

For the year ended December 31, 2010, our average realized price for natural gas was $4.16 per Mcf. For the same period in 2009, our average realized price for natural gas was $3.55 per Mcf. For the year ended December 31, 2010, our average realized price for natural gas was $4.91 per Mcf, including the effect of the realized gains and losses on our natural gas derivatives. For the same period in 2009, our average realized price for natural gas was $6.95 per Mcf, including the effect of the realized gains and losses on our natural gas derivatives. We did not have realized gains or losses on oil derivatives for the year ended December 31, 2010 or 2009.

The difference between our average realized prices inclusive of the hedge realizations in the year ended December 31, 2010 and 2009 periods relates to our natural gas collars and basis swap contracts. During 2010, we had 50,000 MMBtus per day hedged at an average floor price of $6.00 per MMBtu and 50,000 MMBtus per day hedged in our basis swaps and during 2009 we had 20,000 MMBtus natural gas collars at a floor price of $8.75 per MMBtu and 40,000 MMBtus at an average price of $8.35 per MMBtu.

Operating Expenses

Operating expenses in 2011 include an $8.1 million asset impairment, other expense of $0.4 million and a gain on the sale of assets of $0.2 million. Eliminating these non-comparable items from the operating expenses in both 2011 and 2010, the adjusted operating expense of $209.8 million in 2011 increased 12%, or $23.0 million, from adjusted operating expense of $186.8 million in 2010. This increase is primarily attributed to increased depreciation, depletion and amortization (DD&A) expense. The increase in DD&A expense is primarily related to increased oil production from our Eagle Ford Shale Trend wells which carry a higher DD&A rate.

Operating expenses in 2010 include a $234.9 million asset impairment, a $2.8 million loss on sale of assets and other expense of $4.3 million. Eliminating these non-comparable items from the operating expenses in both 2010 and 2009, the adjusted operating expense of $186.8 million in 2010 decreased 23% or $54.7 million from adjusted operating expense of $241.5 million in 2009. This decrease is primarily attributed to lower lease operating expense on our Haynesville Shale wells and decreased DD&A expense because of a lower DD&A rate. The DD&A rate reduction was primarily due to the impairment writedown of the carrying value of our oil and natural gas properties and the addition of the Haynesville Shale reserves with its relatively lower pending costs.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	**2011**	**2010**	**Variance**		**2010**	**2009**	**Variance**	
Lease operating expenses	$ 21,490	$ 26,306	$ (4,816)	(18%)	$ 26,306	$ 30,188	$ (3,882)	(13%)
Production and other taxes	5,450	3,627	1,823	50%	3,627	4,317	(690)	(16%)
Transportation	12,974	9,856	3,118	32%	9,856	9,459	397	4%
Exploration	8,289	10,152	(1,863)	(18%)	10,152	9,292	860	9%

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	**2011**	**2010**	**Variance**		**2010**	**2009**	**Variance**	
Lease operating expenses	$ 0.54	$ 0.78	$ (0.24)	(31%)	$ 0.78	$ 1.01	$ (0.23)	(23%)
Production and other taxes	0.14	0.11	0.03	27%	0.11	0.14	(0.03)	(21%)
Transportation	0.32	0.29	0.03	10%	0.29	0.32	(0.03)	(9%)
Exploration	0.21	0.30	(0.09)	(30%)	0.30	0.31	(0.01)	(3%)

Lease Operating Expense

Lease operating expense (LOE) for the year 2011 decreased overall and on a per unit basis from 2010. The overall cost decrease is a result of our sale in December 2010 of certain high cost non-core gas properties and a greater percentage of our production volumes coming from our Haynesville Shale wells which carry a lower LOE per unit of production. On a per unit basis, LOE decreased for the year 2011 compared to the year 2010 as a result of cost reductions, an increase in production volumes and an increasing portion of our production coming from the lower production cost Haynesville Shale wells.

LOE for the year 2010 decreased from 2009. On a per unit basis, LOE decreased for the year 2010 compared to 2009. The overall cost decrease is attributable to lower saltwater disposal cost as we realized a $2.1 million savings from the continued impact of a series of saltwater disposal systems installed in 2009 and a $1.8 million savings in compression costs as a result of more favorable rental contract rates. On a per unit basis, LOE decreased for the year 2010 compared to the year 2009 as a result of cost reductions, an increase in production volumes and an increasing portion of our production coming from the lower production cost Haynesville Shale wells.

Production and Other Taxes

Production and other taxes for the year 2011 include production tax of $3.9 million and ad valorem tax of $1.6 million. Production tax in 2011 is net of $1.4 million of tax credits attributed to Tight Gas Sands (TGS) credits for our wells in the State of Texas. During the year 2010, production and other taxes included production tax of $1.1 million and ad valorem tax of $2.5 million. Production tax in 2010 is net of $1.6 million of tax credits attributed to TGS credits for our wells in the State of Texas and $0.4 million severance tax relief related to the horizontal wells we have drilled in the State of Louisiana. The higher production tax for 2011 compared to 2010 is attributable to the increasing portion of our production coming from the Eagle Ford Shale oil wells which are not exempt from Texas severance tax.

The TGS tax credits allow for reduced and in many cases the complete elimination of severance taxes in the State of Texas for qualifying wells for up to ten years of production. We only accrue for such credits once we

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have been notified of the State s approval. We anticipate that we will incur a gradually lower production tax rate in the future as we add additional Texas qualifying wells to our production base and as reduced rates are approved.

The Louisiana horizontal wells are eligible for a two year severance tax exemption from the date of first production or until payout of qualified costs, whichever is first.

Ad valorem taxes decreased $0.9 million to $1.6 million in 2011 from $2.5 million in 2010. Ad valorem tax is assessed on the value of properties as of the first day of the year and is highly influenced by commodity prices for the prior several months. The number of properties we owned decreased from January 1, 2010 to January 1, 2011 and the assessed values for our properties were lower year-to-year driven by decreased commodity prices.

Production and other taxes for the year 2010 were $3.6 million which includes production tax of $1.1 million and ad valorem tax of $2.5 million. Production tax in 2010 is net of $1.6 million of tax credits attributed to Tight Gas Sands (TGS) credits for our wells in the State of Texas and $0.4 million severance tax relief related to the horizontal wells we have drilled in the State of Louisiana. During the year 2009, production and other taxes were $4.3 million, which included production tax of $1.3 million and ad valorem tax of $3.0 million. Production tax in 2009 is net of $1.6 million of tax credits attributed to TGS credits for our wells in the State of Texas and $0.2 million severance tax relief related to the horizontal wells we have drilled in the State of Louisiana. The lower production tax for 2010 compared to 2009 is attributable to the increasing portion of our production coming from the Haynesville Shale horizontal wells, which are exempt for two years from State of Louisiana production tax.

Ad valorem taxes decreased $0.5 million to $2.5 million in 2010 from $3.0 million in 2009. Ad valorem tax is assessed on the value of properties as of the first day of the year and is highly influenced by commodity prices for the prior several months. Though the number of properties we owned increased from January 1, 2009 to January 1, 2010, the assessed values for our properties were lower year-to-year driven by decreased commodity prices.

Transportation

Transportation expense increased in 2011 compared to 2010. The increase in expense is primarily a result of higher transportation costs related to our new gas production from the Eagle Ford Shale Trend wells offset by the cost savings from the sale of non-core properties in December 2010.

Transportation expense in 2010 increased compared 2009. The increase in expense is primarily due to our higher production volumes and also up slightly due to a contractual annual volume deficiency charge related to non-core properties while the lower unit costs are a function of our changing geographic production mix, as well as a greater percentage of sales coming from non-operated properties from which the operator nets the transportation cost from revenues.

Exploration

The decrease in exploration expenses in 2011 is attributable primarily to a $0.8 million decrease in exploration labor costs and a $0.6 million decrease in seismic costs. Exploration expense for 2011 includes $5.5 million of amortization of leasehold costs.

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Exploration expenses for 2010 increased from 2009, including an increase in amortization of leasehold cost to $6.0 million from $4.9 million for 2010 and 2009, respectively. Exploration expenses for 2010 include $1.3 million in seismic costs including exploratory seismic costs for our Angelina River Trend area 3-D seismic program, slightly higher undeveloped leasehold cost amortization offset by a decrease in exploration labor cost as compared to 2009.

	Year Ended December 31,				Year Ended December 31,			
(in thousands)	2011	2010	Variance		2010	2009	Variance	
Depreciation, depletion & amortization	$ 131,811	$ 105,913	$ 25,898	24%	$ 105,913	$ 160,361	$ (54,448)	(34%)
Impairment	8,111	234,887	(226,776)	(97%)	234,887	208,905	25,982	12%
General & administrative	29,799	30,918	(1,119)	(4%)	30,918	27,923	2,995	11%
Loss (gain) on sale of assets	(236)	2,824	(3,060)	(108%)	2,824	(297)	3,121	1,051%
Other	448	4,268	(3,820)	(90%)	4,268		4,268	100%

	Year Ended December 31,				Year Ended December 31,			
Per Mcfe	2011	2010	Variance		2010	2009	Variance	
Depreciation, depletion & amortization	$ 3.29	$ 3.14	$ 0.15	5%	$ 3.14	$ 5.38	$ (2.24)	(42%)
Impairment	0.20	6.97	(6.77)	(97%)	6.97	7.01	(0.04)	(1%)
General & administrative	0.74	0.92	(0.18)	(20%)	0.92	0.94	(0.02)	(2%)
Loss (gain) on sale of assets	(0.01)	0.08	(0.09)	(113%)	0.08	(0.01)	0.09	900%
Other	0.01	0.13	(0.12)	(92%)	0.13		0.13	100%

Depreciation, Depletion & Amortization

Our DD&A expense increased in 2011 from 2010 as a result of an increase in production volumes and a greater percentage of our production volumes coming from operating areas with higher DD&A rates, such as our Eagle Ford Shale Trend oil properties. The average DD&A rate increased 5% while production increased 19% year-to-year.

We calculated the first six months of 2011 DD&A rates using the December 31, 2010 reserves prepared by NSAI. Proved developed reserves increased 16% from 165.5 Bcfe at December 31, 2009 to 191.9 Bcfe at December 31, 2010. We calculated the last six months of 2011 DD&A rates using the June 30, 2011 mid-year reserves prepared by internal reserve engineers. Proved developed reserves at June 30, 2011 were 216.8 Bcfe, a 13% increase over the reserves at December 31, 2010.

Our DD&A expense decreased $54.5 million to $105.9 million in 2010 from $160.4 million in 2009 as a result of a lower DD&A rate. The average DD&A rate decreased 42% while production increased 13% year-to-year. The decrease in the average depletion rate contributed $75.5 million to the decrease in DD&A expense offset by $21.0 million attributed to the higher production in 2010.

We calculated the first six months of 2010 DD&A rates using the December 31, 2009 reserves prepared by NSAI. Proved developed reserves increased 9% from 152.5 Bcfe at December 31, 2008 to 165.5 Bcfe at December 31, 2009. We calculated third quarter 2010 DD&A rates using the June 30, 2010 mid-year reserves prepared by internal reserve engineers. Proved developed reserves at June 30, 2010 were 205.8 Bcfe, a 24% increase over the reserves at December 31, 2009. We adjusted our DD&A rates in the fourth quarter of 2010 to reflect the impact of the impairment recorded in the third quarter of 2010.

The decrease in the 2010 DD&A rate was also impacted by the impairment recorded in the fourth quarter of 2009 and the addition of Haynesville Shale proved reserves, which carry more attractive finding and development costs per unit of proved reserves. The 2009 impairment was the result of the write down of our legacy vertical Cotton Valley and Travis Peak proved reserves which reduced the book value of the oil and natural gas properties to be depleted.

While our internal, mid-year reserve reports were prepared in accordance with existing SEC guidelines, they should not be construed as a fully independent reserve report similar to what we have used in the past and what we used at year end.

Impairment

We recorded impairment expense of $8.1 million on four fields for the year ended December 31, 2011, the majority is related to our non-core Beckville field due to falling natural gas prices.

We recorded impairment expense of $234.9 million on several fields for the year ended December 31, 2010, related primarily to a decreasing projected natural gas price environment resulting in the write down of the carrying values of certain non-core assets. In addition to lower commodity prices, the impairment was a result of our change in forward looking development plans, which will focus on the Eagle Ford Shale Trend, core Haynesville Shale in Northwest Louisiana and the Angelina River Trend of the Shelby Trough.

We recorded an impairment of $208.9 million in 2009 related to the Bethany Longstreet, Bethune/East Gates, Loco Bayou, Cotton South/Raintree and a collection of other fields as a result of the decrease in natural gas prices in 2009 from 2008 which lowered economical proved reserves. Proved and probable reserves were also lowered due to our strategic decision to decrease using vertical wellbores to develop our existing properties because this method was deemed no longer the most economic avenue to pursue. The impairment charge in 2009 was also driven by the removal of the previously scheduled vertical proved and probable drilling locations and was partially offset by the addition of horizontal undeveloped locations in fields where such locations were deemed appropriate.

General and Administrative Expense

General and administrative (G&A) expense decreased in 2011 compared to 2010. The decrease relates primarily to the partial refund and final settlement of a Louisiana State franchise tax payment made under protest in 2007, decreases in stock based compensation and consulting cost. Share based compensation expense, which is a non-cash item, amounted to $6.5 million in 2011 compared to $7.6 million in 2010. G&A on a per unit basis decreased to $0.74 per Mcfe from $0.92 per Mcfe as a result of the 19% increase in production volume in 2011 compared to 2010.

G&A expense increased in 2010 compared to 2009. G&A expense in 2010 included compensation costs related to the resignation of an officer of the company. See *Note 14 Resignation of Executive Officer in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K* for more information. G&A expense for the year 2010 also includes certain 2009 bonuses approved and paid out in March 2010. Share based compensation expense, which is a non-cash item, amounted to $7.6 million in 2010 compared to $6.8 million in 2009. G&A on a per unit basis decreased to $0.92 per Mcfe from $0.94 per Mcfe as a result of the 13% increase in production volume in 2010 compared to 2009.

Gain on Sale of Assets

We recorded a gain of $0.2 million on the sale on non-core oil and natural gas properties in the year ended December 31, 2011. We recorded a loss of $2.8 million on the sale of assets in the year ended December, 31, 2010 and a $0.3 million gain on the sale of assets in the year ended December 31, 2009.

Other

Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC et al. On April 29, 2010 a state court in Caddo Parish, Louisiana, granted a judgment holding us solely responsible for the payment of $8.5 million in additional oil and natural gas lease bonus payments and related interest in an ongoing lawsuit involving the interpretation of a unique oil and natural gas lease provision. The lease provided for the payment of additional bonuses under certain circumstances in the event higher lease bonuses were paid by us, or our successors or assigns, within the surrounding area. Without our knowledge, one of the sub-lessees subject to the same lease paid substantially higher bonuses in the area. We accrued the full amount of $8.5 million as expense in the first quarter of 2010.

On July 9, 2010, the sub-lessee agreed to reimburse us for one half of any sums for which we may be cast in judgment in this lawsuit in any final non-appealable judgment. We reduced our accrual by $4.2 million in the third quarter of 2010 and the remaining $4.3 million as of December 31, 2010 is reflected as *Operating Expenses Other in the Consolidated Statement of Operations in Part II Item 8 of this Annual Report on Form 10-K.*

On June 10, 2011, we filed an application for writ of certiorari with the Supreme Court of Louisiana which was denied on September 23, 2011. On October 13, 2011, the money judgment of $4.4 million, including interest, was paid to the plaintiffs consequently another $0.1 million was recorded in 2011 to Other as a result of the settlement. We accrued an additional $0.3 million to Other in 2011 representing potential settlements on two other minor litigation actions for a total of $0.4 million as of December 31, 2011 reflected as *Operating Expenses Other in the Consolidated Statement of Operations in Part II Item 8 of this Annual Report on Form 10-K.*

Other Income (Expense)

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Other Income (Expense):			
Interest expense	$ (49,351)	$ (37,179)	$ (26,148)
Interest income and other	59	117	458
Gain on derivatives not designated as hedges	34,539	55,275	47,115
Gain on extinguishment of debt	62		
Income tax benefit (expense)		85	67,311
Average funded borrowings adjusted for debt discount	508,323	379,582	268,000
Average funded borrowings	543,688	400,405	304,211

Interest Expense

Interest expense increased in 2011 compared to 2010 as a result of the higher average level of outstanding debt in the current year. The higher average level of debt resulted from the issuance of our $275 million 8.875% Senior Notes due 2019 (the 2019 Notes). Non-cash interest of $14.4 million is included in the interest expense reported in 2011. Non-cash interest of $19.3 million is included in the interest expense reported for the year 2010.

Interest expense increased in 2010 compared to 2009 as a result of the higher average level of outstanding debt in the current year. The higher average level of debt is the result of the issuance of our 5% convertible senior notes in September 2009. Non-cash interest of $19.3 million is included in the interest expense reported in 2010. Non-cash interest of $12.2 million is included in the interest expense reported for the year 2009.

Interest Income and Other

We invested the proceeds from the 5% convertible senior note offering in September 2009 in money market funds and time deposits with certain acceptable institutions, subject to our Short Term Investment Policy. We used the invested proceeds throughout 2010 and 2009 to fund our capital program. The income earned on these investments during 2011, 2010 and 2009 is reflected in the Interest income line.

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Gain on Derivatives Not Designated as Hedges

We produce and sell oil and natural gas into a market where selling prices are historically volatile. For example, on June 10, 2011 the Henry Hub natural gas spot price reached a high of $4.92 per MMBtu, but the price was down to $2.80 per MMBtu at November 28, 2011. We enter into swap contracts, swaptions, costless collars or other derivative agreements from time to time to manage commodity price risk for a portion of our production.

Gain on derivatives not designated as hedges was $34.5 million for 2011. The gain includes a realized gain of $31.3 million on our natural gas derivatives and an unrealized gain of $3.2 million for the change in fair value of our oil and natural gas commodity contracts. The unrealized gain reflects the lower average futures strip prices from December 31, 2010 as compared to December 31, 2011.

Gain on derivatives not designated as hedges was $55.3 million for 2010. The gain includes a realized gain of $24.6 million on our natural gas derivatives and an unrealized gain of $30.7 million for the change in fair value of our oil and natural gas commodity contracts. The unrealized gain reflects the lower average futures strip prices from December 31, 2009 as compared to December 31, 2010.

Gain on derivatives not designated as hedges was $47.1 million for 2009, which includes a gain of $47.8 million from our natural gas derivatives offset by a $0.7 million loss on our interest rate derivatives. The gain on our natural gas derivatives includes a realized gain of $98.0 million offset by a $50.2 million unrealized loss for the change in fair value of our natural gas commodity contracts. The unrealized loss resulted from the roll off of existing natural gas derivative contracts during 2009. The loss on interest rate hedges in 2009 includes a realized loss of $1.4 million offset by an unrealized gain of $0.7 million. Our interest rate derivative contracts expired in the first half of 2010.

We will continue to be exposed to volatility in earnings resulting from changes in the fair value of our commodity contracts when we do not designate these contracts as hedges.

Income Tax Benefit

We recorded no income tax benefit for the year 2011. We increased our valuation allowance and reduced our net deferred tax assets to zero during 2009 after considering all available positive and negative evidence related to the realization of our deferred tax assets. Our assessment of the realization of our deferred tax assets has not changed and as a result, we continue to maintain a full valuation allowance for our net deferred asset as of December 31, 2011.

We recorded a small tax benefit of less than $0.1 million in 2010, which reflects the monetization of our alternative minimum tax credit. We otherwise recorded no income tax benefit for the year 2010. Income tax benefit of $67.3 million for 2009 includes an increase to our valuation allowance of $54.3 million.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Our primary sources of cash during 2011 were from cash on hand, cash flow from operating activities, available borrowings under our Senior Credit Facility and our issuance in March 2011 of $275 million of our 2019 Notes. We used cash primarily to fund our capital spending program, retire debt and pay preferred stock dividends. Our primary sources of cash during 2010 were from cash on hand, cash flow from operating activities and proceeds from divestitures. In 2010, we used cash primarily to fund our capital spending program, and pay preferred stock dividends. Our primary sources of cash during 2009 were cash flow from operating activities and the issuance of debt. In 2009, we used cash primarily to fund our capital spending program, retire debt and pay preferred stock dividends.

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We have in place a $600 million Senior Credit Facility, entered into with a syndicate of U.S. and international lenders. As of December 31, 2011, we had a $275 million borrowing base with $102.5 million outstanding. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The Fourth Amendment became effective upon the closing of the issuance and sale of our 2019 Notes, which occurred on March 2, 2011, and the placement of $175 million of net proceeds in an escrow account which was used for the redemption $174.6 million of our $3.25% Convertible Senior Notes due 2026 (the 2026 Notes). In October 2011, we entered into the Sixth Amendment which increased our borrowing base to $275 million. We were in compliance with existing covenants, as amended, at December 31, 2011.

We continuously monitor our leverage position and coordinate our capital program with our expected cash flows and repayment of our projected debt. We will continue to evaluate funding alternatives as needed.

Alternatives available to us include:

- sale of non-core assets,
- joint venture partnerships in our core Haynesville Shale and/or Eagle Ford Shale Trend acreage,
- availability under our Senior Credit Facility, and
- issuance of debt securities.

We have also supported our future cash flows by entering into derivative positions and as of December 31, 2011, were covering approximately 55-60% of our projected oil and natural gas sales volumes for 2012. See *Note 8 Derivative Activities in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

The following section discusses significant sources and uses of cash for the three-year period ending December 31, 2011. Forward-looking information related to our liquidity and capital resources are discussed in *Outlook* that follows.

Capital Resources

We intend to fund our capital expenditure program, contractual commitments, including settlement of derivative contracts and future acquisitions with cash flows from our operations and borrowings under our Senior Credit Facility. In the future, as we have done on several occasions over the last few years, we may also access public markets to issue additional debt and/or equity securities.

Our primary sources of cash during 2011 were from cash on hand, cash flow from operating activities, available borrowings under our Senior Credit Facility and our issuance of the 2019 Notes.

Primary sources of cash during 2010 were cash flow from operating activities and sale of assets.

Our primary sources of cash during 2009 were from our issuance of $218.5 million of 5% convertible senior notes due 2029 in September 2009, funds generated from operations and bank borrowings. Cash was used primarily to fund exploration and development expenditures.

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The table below summarizes the sources of cash during 2011, 2010 and 2009:

Cash flow statement information:	Year Ended December 31, 2011	Year Ended December 31, 2010	Variance	Year Ended December 31, 2010	Year Ended December 31, 2009	Variance
	(In thousands)					
Net Cash:						
Provided by operating activities	$ 136,340	$ 100,432	$ 35,908	$ 100,432	$ 115,570	$ (15,138)
Used in investing activities	(335,064)	(200,080)	(134,984)	(200,080)	(265,587)	65,507
Provided by (used) financing activities	184,283	(7,680)	191,963	(7,680)	127,585	(135,265)
Increase (decrease) in cash and cash equivalents	$ (14,441)	$ (107,328)	$ 92,887	$ (107,328)	$ (22,432)	$ (84,896)

At December 31, 2011, we had a working capital deficit of $13.7 million and long-term debt, net of debt discount, of $566.1 million.

Cash Flows

Year ended December 31, 2011 Compared to Year Ended December 31, 2010

Operating activities. Production from our wells, the price of oil and natural gas and operating costs represent the main drivers behind our cash flow from operations. Changes in working capital also impact cash flows. Net cash provided by operating activities increased $35.9 million this year. Cash received related to oil and natural gas revenue increased $47.2 million year over year with (i) a 19% increase in total production, (ii) growth in oil volumes as a percentage of total volumes from 3% in 2010 to 10% in 2011, and (iii) a 14% increase in the average realized sales price from $4.39 to $5.01 per Mcfe. Operating costs savings of $7.9 million in 2011 as compared to 2010 and $7.9 million in additional realized cash settlements on our derivative contracts were also additive to cash flow from operations. Offsetting decreases to cash flow in 2011 include (i) $17.2 million in additional cash interest paid in 2011 as we replaced $175 million of our 3.25% Convertible Senior Notes due 2026 with $275 million of our 8.875% 2019 Notes and (ii) $9.9 million in working capital changes.

Investing activities. Net cash used in investing activities was $335.1 million for the year ended December 31, 2011, compared to $200.1 million for 2010. While we booked capital expenditures of approximately $330.2 million in 2011, we paid out cash amounts totaling $335.2 million in 2011, with the difference being attributed to approximately $22.3 million in drilling and completion costs which were accrued at December 31, 2011, non-cash asset retirement obligation additions of $2.1 million and geophysical and geological cost of $0.6 million offset by $30.0 million in drilling and completion cost accrued at December 31, 2010 and paid in 2011. Net cash used in investing activities was offset by the receipt of $0.2 million of cash proceeds from the sale of fixed assets in 2011.

We drilled 47 gross wells in 2011 compared to 46 gross wells in 2010. Of the $335.2 million cash spent in 2011, $299.9 million was for drilling and completion activities (of which $29.8 million related to 2010 wells); $22.7 million was for leasehold acquisition, $9.2 million for facilities and infrastructure, $2.8 million for capital workovers and $0.6 million for furniture, fixtures and equipment. Of the $265.0 million cash spent in 2010, approximately $227.6 million was for drilling and completion activities (of which $13.8 million related to 2009 wells); $33.7 million was for leasehold acquisition, $0.6 million for facilities and infrastructure, $2.3 million for capital workovers, and $0.8 million for furniture, fixtures and equipment.

Financing activities. The net cash provided by financing activities for 2011 consisted primarily of proceeds from the issuance of $275 million of the 2019 Notes and net borrowings under our Senior Credit Facility of $102.5 million, partially offset by the redemption of a portion of our 2026 Notes totaling $176.4 million, financing cost on the issuance of the 2019 Notes of $9.3 million and preferred stock dividends of $6.0 million. We had $102.5 million borrowings outstanding under our Senior Credit Facility as of December 31, 2011. In 2010 we had no issuances of debt or equity and the cash used in financing activities was primarily the dividend paid on preferred stock.

Year ended December 31, 2010 Compared to Year Ended December 31, 2009

Operating activities. Net cash provided by operating activities was $100.4 million, an increase of $15.1 million, or 13%, from $115.6 million in 2009. Our operating revenues increased 34% in 2010 with an 18% decrease in commodity prices and an increase in average daily production of 13% as compared to 2009. The cash flow decrease was primarily the result of receiving $24.6 million in natural gas derivative settlements in 2010 compared to having received $98.0 million for settlements of natural gas derivatives in 2009.

Investing activities. Net cash used in investing activities was $200.1 million for the year ended December 31, 2010, compared to $265.6 million for 2009. While we booked capital expenditures of approximately $283.7 million in 2010, we paid out cash amounts totaling $265.0 million in 2010, with the difference being attributed to approximately $30.0 million in drilling and completion costs which were accrued at December 31, 2010, non-cash asset retirement obligation additions of $1.3 million and geophysical and geological cost of $1.2 million offset by $13.8 million in drilling and completion cost accrued at December 31, 2009 and paid in 2010. In the fourth quarter of 2010, we incurred additional drilling and completion capital expenditures in excess of that which was budgeted from (1) acceleration of completion of Haynesville Shale wells that were scheduled for 2011; (2) incremental drilling and completion costs associated with longer laterals in our Eagle Ford Shale Trend; and (3) reduced drilling cycles thereby incurring additional drilling capital expenditures as a result of drilling more wells. Net cash used in investing activities was offset by the receipt of $64.9 million of cash proceeds from the sale of fixed assets in 2010.

We conducted drilling and completion operations on 46 gross wells in 2010 compared to 45 gross wells in 2009. Of the $265.0 million cash spent in 2010, approximately $227.6 million was for drilling and completion activities (of which $13.8 million related to 2009 wells), $33.7 million was for leasehold acquisition, $0.6 million for facilities and infrastructure, $2.3 million for capital workovers, and $0.8 million for furniture, fixtures and equipment. Of the $265.8 million spent in 2009, approximately $239.5 million was for drilling and completion activities (of which $28.3 million related to 2008 wells), $15.9 million was for leasehold acquisition, $4.1 million for facilities and infrastructure, $3.4 million for capital workovers, $1.9 million on geological and geophysical and $1.0 million for furniture, fixtures and equipment.

Financing activities. Net cash used in financing activities was $7.7 million for 2010, a decrease of $135.3 million from net cash provided by financing activities of $127.6 million in 2009. In September 2009, we received $218.5 million from the offering of our 5% convertible senior notes due 2029. With the proceeds from the offering, we paid $8.8 million in offering cost, paid off our $75.0 million second lien term loan and paid off the $5.0 million balance on our senior credit facility. We had zero borrowings outstanding under our Senior Credit Facility as of December 31, 2010.

Debt consisted of the following balances (in thousands):

	December 31, 2011			December 31, 2010		
	Principal	Carrying Amount	Fair Value	Principal	Carrying Amount	Fair Value
Senior Credit Facility	$ 102,500	$ 102,500	$ 102,500	$	$	$
3.25% Convertible Senior Notes due 2026 (1)	429	429	429	175,000	167,086	173,478
5.0% Convertible Senior Notes due 2029 (2)	218,500	188,197	201,785	218,500	179,171	212,164
8.875% Senior Notes due 2019	275,000	275,000	243,898			
Total debt	$ 596,429	$ 566,126	$ 548,612	$ 393,500	$ 346,257	$ 385,642

(1) The debt discount was amortized using the effective interest rate method based upon an original five year term through December 1, 2011.
(2) The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014.

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Interest Expense The following table summarizes the total interest expense relating to contractual interest rate, amortization of debt discount and financing costs (in thousands) and the effective interest rate on the liability component the debt excluding the Senior Credit Facility.

	2011		2010		2009	
	Interest Expense	**Effective Interest Rate**	**Interest Expense**	**Effective Interest Rate**	**Interest Expense**	**Effective Interest Rate**
3.25% Convertible Senior Notes due 2026	$ 4,305	9.0%	$ 14,537	9.0%	$ 13,900	9.0%
5.0% Convertible Senior Notes due 2029	20,948	10.5%	20,031	11.2%	5,043	11.2%
8.875% Senior Notes due 2019	20,910	8.9%				

Senior Credit Facility

On May 5, 2009, we entered into a Second Amended and Restated Credit Agreement (including all amendments, the Senior Credit Facility) that replaced our previous facility. On February 25, 2011, we entered into a Fourth Amendment to the Senior Credit Facility. The primary conditions for the effectiveness of the Fourth Amendment were (i) the closing of the issuance and sale of our 2019 Notes, and (ii) the placement of not less than $175 million of net proceeds from the sale of the 2019 Notes in an escrow account with the lenders to be used for the redemption or earlier repurchase of all our outstanding 3.25% Convertible Senior Notes due 2026 (the 2026 Notes), both of which occurred on March 2, 2011.

Total lender commitments under the Senior Credit Facility are $600 million subject to borrowing base limitations as of December 31, 2011 of $275 million. The Senior Credit Facility matures on July 1, 2014 (subject to automatic extension to February 25, 2016, if, prior to maturity, we prepay or escrow certain proceeds sufficient to prepay our $218.5 million 5% Convertible Senior Notes due 2029 (the 2029 Notes). Revolving borrowings under the Senior Credit Facility are limited to, and subject to, periodic redeterminations of the borrowing base. Interest on revolving borrowings under the Senior Credit Facility accrues at a rate calculated, at our option, at the bank base rate plus 1.00% to 1.75%, or LIBOR plus 2.00% to 2.75%, depending on borrowing base utilization. Pursuant to the terms of the Senior Credit Facility, borrowing base redeterminations occur on a semi-annual basis on April 1 and October 1. As of December 31, 2011, we had $102.5 million outstanding under the Senior Credit Facility. Substantially all our assets are pledged as collateral to secure the Senior Credit Facility. Availability under the Senior Credit Facility as of December 31, 2011 was $172.5 million.

The terms of the Senior Credit Facility require us to maintain certain covenants. Capitalized terms used here, but not defined, have the meanings assigned to them in the Senior Credit Facility. In October 2011, we entered into a Sixth Amendment to the Senior Credit Facility which amended the EBITDAX annualized calculation and increased the borrowing base to $275 million. The primary financial covenants include:

Current Ratio of 1.0/1.0;

Interest Coverage Ratio of EBITDAX of not less than 2.5/1.0 for the trailing four quarters or when measured for the third and fourth quarters of 2011 and the first quarter of 2012, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters. The interest for such period to apply solely to the cash portion of interest expense; and

Total Debt no greater than 4.0 times EBITDAX for the trailing four quarters. Total Debt used in such ratio to be reduced by the amount of any restricted cash held in an escrow account established for the benefit of the lenders and dedicated to the redemption or prepayment of the 2026 Notes, the 2029 Notes or the 2019 Notes; provided that such ratios, when measured for the third and fourth quarters of 2011 and the first quarter of 2012, shall be based on annualized interim EBITDAX amounts rather than trailing four quarters.

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As defined in the credit agreement EBITDAX is earnings before interest expense, income tax, DD&A, exploration expense, stock based compensation and impairment of oil and natural gas properties. In calculating EBITDAX for this purpose, earnings include realized gains (losses) from derivatives not designated as hedges but exclude unrealized gains (losses) from derivatives not designated as hedges.

We were in compliance with all the financial covenants of the Senior Credit Facility as of December 31, 2011.

8.875% Senior Notes due 2019

On March 2, 2011, we sold $275 million of our 2019 Notes. The 2019 Notes mature on March 15, 2019, unless earlier redeemed or repurchased. The 2019 Notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The 2019 Notes accrue interest at a rate of 8.875% annually, and interest is paid semi-annually in arrears on March 15 and September 15. The 2019 Notes are guaranteed by our subsidiary that also guarantees our Senior Credit Facility.

Before March 15, 2014, we may on one or more occasions redeem up to 35% of the aggregate principal amount of the 2019 Notes at a redemption price of 108.875% of the principal amount of the 2019 Notes, plus accrued and unpaid interest to the redemption date, with the net cash proceeds of certain equity offerings. On or after March 15, 2015, we may redeem all or a portion of the 2019 Notes at redemption prices (expressed as percentages of principal amount) equal to (i) 104.438% for the twelve-month period beginning on March 15, 2015; (ii) 102.219% for the twelve-month period beginning on March 15, 2016 and (iii) 100.000% on or after March 15, 2017, in each case plus accrued and unpaid interest to the redemption date. In addition, prior to March 15, 2015, we may redeem all or a part of the 2019 Notes at a redemption price equal to 100% of the principal amount of the 2019 Notes to be redeemed plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

The indenture governing the 2019 Notes restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt; (ii) make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem or retire such capital stock; (iii) sell assets, including the capital stock of our restricted subsidiaries; (iv) pay dividends or other payments of our restricted subsidiaries; (v) create liens that secure debt; (vi) enter into transactions with affiliates and (vii) merge or consolidate with another company. These covenants are subject to a number of important exceptions and qualifications. At any time when the 2019 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the indenture governing the 2019 Notes) has occurred and is continuing, many of these covenants will terminate.

5% Convertible Senior Notes due 2029

In September 2009, we sold $218.5 million of 5% convertible senior notes due in October 2029 (the 2029 Notes). The notes mature on October 1, 2029, unless earlier converted, redeemed or repurchased. The notes are our senior unsecured obligations and rank equally in right of payment to all of our other existing and future indebtedness. The notes accrue interest at a rate of 5% annually, and interest is paid semi-annually in arrears on April 1 and October 1 of each year, beginning in 2010.

Before October 1, 2014, we may not redeem the notes. On or after October 1, 2014, we may redeem all or a portion of the notes for cash, and the investors may require us to repurchase the notes on each of October 1, 2014, 2019 and 2024. Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares.

Investors may convert their notes at their option at any time prior to the close of business on the second business day immediately preceding the maturity date under the following circumstances: (1) during any fiscal quarter (and only during such fiscal quarter) commencing after December 31, 2009, if the last reported sale price of our common stock is greater than or equal to 135% of the conversion price of the notes (as defined in this prospectus supplement) for at least 20 trading days in the period of 30 consecutive trading days ending on the last trading day of the preceding fiscal quarter; (2) prior to October 1, 2014, during the five business-day period after any ten consecutive trading-day period (the measurement period) in which the trading price of $1,000 principal amount of notes for each trading day in the measurement period was less than 97% of the product of the last reported sale price of our common stock and the conversion rate on such trading day; (3) if the notes have been called for redemption; or (4) upon the occurrence of one of the specified corporate transactions described in this prospectus supplement. Investors may also convert their notes at their option at any time beginning on September 1, 2029, and ending at the close of business on the second business day immediately preceding the maturity date.

The notes are convertible into shares of our common stock at a rate equal to 28.8534 shares per $1,000 principal amount of notes (equal to an initial conversion price of approximately $34.66 per share of common stock per share).

Proceeds received from the issuance of the 2029 Notes were used, in part, to fully pay-off a second lien term loan of $75 million and for general corporate purposes.

We separately account for the liability and equity components of our 5% convertible senior notes due 2029 in a manner that reflects our nonconvertible debt borrowing rate when interest is recognized in subsequent periods. Upon issuance of the notes in September 2009, in accordance with accounting standards related to convertible debt instruments that may be settled in cash upon conversion, we recorded a debt discount of $49.4 million, thereby reducing the carrying the value of $218.5 million notes on the December 31, 2009 balance sheet to $171.1 million and recorded an equity component net of tax of $32.1 million. The debt discount is amortized using the effective interest rate method based upon an original five year term through October 1, 2014.

3.25% Convertible Senior Notes Due 2026

During the year ended December 31, 2011, we repurchased $174.6 million of our 2026 Notes for $176.4 million using a portion of the net proceeds from the issuance of our 2019 Notes. We recorded a $0.1 million gain on the early extinguishment of debt related to the repurchase for the year ended December 31, 2011.

At December 31, 2011, $0.4 million of the 2026 Notes remained outstanding. Holders may present to us for redemption the remaining outstanding 2026 Notes on December 1, 2016 and December 1, 2021.

Upon conversion, we have the option to deliver shares at the applicable conversion rate, redeem in cash or in certain circumstances redeem in a combination of cash and shares.

The notes are convertible into shares of our common stock at a rate equal to the sum of:

a) 15.1653 shares per $1,000 principal amount of notes (equal to a base conversion price of approximately $65.94 per share) plus

b) an additional amount of shares per $1,000 of principal amount of notes equal to the incremental share factor 2.6762), multiplied by a fraction, the numerator of which is the applicable stock price less the base conversion price and the denominator of which is the applicable stock price

For additional information on our debt instruments, see *Note 4 Debt in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Preferred Stock

Our Series B Convertible Preferred Stock (the Series B Convertible Preferred Stock) was initially issued on December 21, 2005, in a private placement of 1,650,000 shares for net proceeds of $79.8 million (after

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offering costs of $2.7 million). Each share of the Series B Convertible Preferred Stock has a liquidation preference of $50 per share, aggregating to $82.5 million, and bears a dividend of 5.375% per annum. Dividends are payable quarterly in arrears.

On January 23, 2006, the initial purchasers of the Series B Convertible Preferred Stock exercised their over-allotment option to purchase an additional 600,000 shares at the same price per share, resulting in net proceeds of $29.0 million, which was used to fund our 2006 capital expenditure program.

For additional information on our debt instruments, see *Note 7 Stockholder s Equity in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Outlook

The Company s capital budgeting process is ongoing. Our total budget for capital expenditures for 2012 is expected to be $250 million, exclusive of acquisitions other than lease acreage additions in our core areas. We expect capital spending by area to be approximately 70% in the Eagle Ford Shale Trend, 14% in the Haynesville Shale Trend, 8% in the Tuscaloosa Marine Shale and the remaining 8% in other areas. The Company s primary emphasis will be on managing near-term growth opportunities. We believe that our expected level of operating cash flows, cash on hand as of December 31, 2011, and our borrowing base will be sufficient to fund our projected operational and capital programs for 2012. However, if capital expenditures exceed operating cash flow and cash on hand, funds would likely be supplemented as needed through short-term borrowings under our senior credit facility or through the issuance of debt or equity.

We will operate approximately 63% of wells drilled as part of our 2012 planned capital expenditures. Additionally, we operate 70% of our proved reserves and 37% of our acreage is held by production. We have two drilling commitments and the option not to participate on all wells proposed by partners.

As we increase our oil production in 2012, we expect that our overall operating expenses will increase as a result of the higher DD&A rates associated with oil wells compared to our natural gas wells.

In addition, to support 2012 cash flows, we entered into strategic derivative positions as of December 31, 2011, on approximately 60% of our anticipated natural gas sales volumes and approximately 55-60% of our anticipated oil and condensate sales volumes for 2012. See *Note 8 Derivative Activities in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

We may choose to refinance certain portions of our short-term borrowings by issuing long-term debt or equity, or both. We continuously monitor our leverage position and coordinate our capital expenditure program with our expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives as needed, including property divestitures, borrowings under our Senior Credit Facility, the issuance of debt or equity securities and/or bringing in joint venture partners in our core Haynesville Shale and/or Eagle Ford Shale Trend acreage.

Our next borrowing base redetermination is currently scheduled for April 2012. At December 31, 2011, our borrowing base under our Senior Credit Facility is $275 million with $102.5 million outstanding. Our borrowing base is typically reviewed twice annually by our bank group using their price deck applied to our most recent reserve report, in this case as of December 31, 2011. While the current low natural gas price environment may negatively impact our current borrowing base at the April 2012 redetermination, we expect the additional oil reserves in our year end reserve report as of December 31, 2011 and our current open oil and natural gas derivative positions to positively impact the April 2012 redetermination.

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Credit Risks

Our exposure to non-payment or non-performance by our customers and counterparties presents a credit risk. Generally, non-payment or non-performance results from a customer s or counterparty s inability to satisfy obligations. We monitor the creditworthiness of our customers and counterparties and established credit limits according to our credit policies and guidelines. We have the ability to require cash collateral as well as letters of credit from our financial counterparties to mitigate our exposure above assigned credit thresholds. We routinely exercise our contractual right to net realized gains against realized losses when settling with our financial counterparties.

Future Commitments

The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2011 (in thousands). In addition to the contractual obligations presented in the table below, our Consolidated Balance Sheet at December 31, 2011 reflects accrued interest on our bank debt of $10.0 million payable in the first half of 2012. For additional information see *Note 4 Long-Term Debt* and *Note 10 Commitments and Contingencies in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

			Payment due by Period				
	Note	**Total**	**2012**	**2013**	**2014**	**2015**	**2016 and After**
Contractual Obligations							
Long term debt (1)	4	$ 493,929	$	$	$ 218,500	$	$ 275,429
Interest on convertible senior notes	4	132,822	35,345	35,345	32,614	24,420	5,098
Office space leases	9	8,204	1,044	1,142	1,104	983	3,931
Office equipment leases	9	894	427	316	121	30	
Drilling rigs & operations contracts	9	13,216	13,055	60	60	41	
Transportation contracts	9	9,335	1,592	1,936	1,936	1,936	1,935
Total contractual obligations (2)		$ 658,400	$ 51,463	$ 38,799	$ 254,335	$ 27,410	$ 286,393

(1) The 2026 Notes have a provision at the end of years 5, 10 and 15, for the investors to demand payment on these dates; the first such date was December 1, 2011; all but the remaining $0.4 million were redeemed. The next put date for the remaining 2026 Notes is December 1, 2016. The $218.5 million 5.0% convertible senior notes have a provision by which on or after October 1, 2014, the Company may redeem all or a portion of the notes for cash, and the investors may require the Company to repurchase the notes on each of October 1, 2014, 2019 and 2024.

(2) This table does not include the estimated liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $17.4 million. The Company records a separate liability for the fair value of this asset retirement obligation. See *Note 3 Asset Retirement Obligation in the Notes to Consolidated Financial Statements in Part II Item 8 of this Form 10-K.*

Summary of Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list in *Note 1 Description of Business and Accounting Policies in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Proved Oil and Natural Gas Reserves

Proved reserves are defined by the SEC as those quantities of oil and natural gas which, by analysis of geosciences and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserves estimates if the extraction is by means not involving a well. Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates used by us. We cannot predict the types of reserve revisions that will be required in future periods.

While the estimates of our proved reserves at December 31, 2011 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the new SEC rules, those estimates could differ materially from any estimates we might prepare applying more specific SEC interpretive guidance.

Successful Efforts Accounting

We use the successful efforts method to account for exploration and development expenditures and to calculate DD&A. Unsuccessful exploration wells, as well as other exploration expenditures such as seismic costs, are expensed and can have a significant effect on operating results. Successful exploration drilling costs, all development capital expenditures and asset retirement costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and natural gas reserves as estimated by engineers. Leasehold costs are charged to expense using the units of production method based on total proved oil and natural gas reserves.

Fair Value Measurement

Fair value is defined by Accounting Standards Codification (ASC) § 820 as 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. We carry our derivative instruments at fair value and measure their fair value by applying the income approach provided for ASC 820, using Level 2 inputs based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our credit worthiness or that of our counterparties. We carry our oil and natural gas properties held for use at historical cost. We use Level 3 inputs, which are unobservable data such as discounted cash flow models or valuations, based on the Company s various assumptions and future commodity prices to determine the fair value of our oil and natural gas properties in determining impairment. We carry cash and cash equivalents, account receivables and payables at carrying value which represent fair value because of the short-term nature of these instruments. For definitions for Level 1, Level 2 and Level 3 inputs see *Note 1 Description of Business and Accounting Policies in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Impairment of Properties

We monitor our long-lived assets recorded in oil and natural gas properties in the Consolidated Balance Sheets to ensure that they are not carried in excess of fair value. We must evaluate our properties for potential impairment when certain indicators or circumstances indicate that the carrying value of an asset could exceed its fair value. Performing these evaluations requires a significant amount of judgment since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable proved and probable oil and natural gas reserves that will be produced from a field, the timing of this future production, future costs to produce the oil and natural gas, and future inflation levels. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or natural gas, unfavorable adjustments to reserves or other changes to contracts, environmental regulations or tax laws. We cannot predict the amount of impairment charges that may be recorded in the future.

Asset Retirement Obligations

We make estimates of the future costs of the retirement obligations of our producing oil and natural gas properties in order to record the liability as required by the applicable accounting standard. This requirement necessitates us to make estimates of our property abandonment costs that, in some cases, will not be incurred until a substantial number of years in the future. Such cost estimates could be subject to significant revisions in subsequent years due to changes in regulatory requirements, technological advances and other factors which may be difficult to predict.

Income Taxes

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. We periodically evaluate our tax operating loss and other carry-forwards to determine whether a gross deferred tax asset, as well as a related valuation allowance, should be recognized in our financial statements.

Accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority. See *Note 1 Description of Business and Accounting Policies-Income Taxes* and *Note 6 Income Taxes in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Share-Based Compensation Plans

For all new, modified and unvested share-based payment transactions with employees, we measure the fair value on the grant date and recognize it as compensation expense over the requisite period. The fair value of each option award is estimated using a Black-Scholes option valuation model that requires us to develop estimates for assumptions used in the model. The Black-Scholes valuation model uses the following assumptions: expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore the dividend yield is zero. The fair value of restricted stock is measured using the close of the day stock price on the day of the award.

New Accounting Pronouncements

See *Note 1 Description of Business and Accounting Policies New Accounting Pronouncements in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Off-Balance Sheet Arrangements

We do not currently use any off-balance sheet arrangements to enhance our liquidity and capital resource positions, or for any other purpose.

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

The Company s primary market risks are attributable to fluctuations in commodity prices and interest rates. These fluctuations can affect revenues and cash flow from operating, investing and financing activities. The Company s risk-management policies provide for the use of derivative instruments to manage these risks. The types of derivative instruments utilized by the Company include futures, swaps, options and fixed-price physical-delivery contracts. The volume of commodity derivative instruments utilized by the Company may vary from year to year and is governed by risk-management policies with levels of authority delegated by the Board of Directors. Both exchange and over-the-counter traded commodity derivative instruments may be subject to margin deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or its counterparties in order to satisfy these margin requirements.

For information regarding the Company s accounting policies and additional information related to the Company s derivative and financial instruments, see *Note 1 Summary of Significant Accounting Policies , Note 8 Derivative Instruments* and *Note 4 Debt and Interest Expense in the Notes to Consolidated Financial Statements in Part II Item 8 of this Annual Report on Form 10-K.*

Commodity Price Risk

The Company s most significant market risk relates to fluctuations in natural gas and crude oil prices. Management expects the prices of these commodities to remain volatile and unpredictable. As these prices decline or rise significantly, revenues and cash flow will also decline or rise significantly. In addition, a non-cash write-down of the Company s oil and natural gas properties may be required if future commodity prices experience a sustained and significant decline. Below is a sensitivity analysis of the Company s commodity-price-related derivative instruments.

The Company had derivative instruments in place to reduce the price risk associated with production in 2012 of approximately 60 MMBtus per day of natural gas and 2 MBbls per day of crude oil as of December 31, 2011. At December 31, 2011, the Company had a net asset derivative position of $39.1 million related to these derivative instruments. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $6.8 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $22.8 million. However, a gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instruments.

Interest Rate Risk

As of December 31, 2011, we had $102.5 million outstanding variable-rate debt and $493.9 million of principal fixed-rate debt. To the extent we incur borrowings under our Senior Credit Facility, our exposure to variable interest rates will increase. In the past, we have entered into interest rate swaps to help reduce our exposure to interest rate risk, and we may seek to do so in the future if we deem appropriate. As of December 31, 2011, we have no interest rate swaps.

Item 8. ***Financial Statements and Supplementary Data***

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT S ANNUAL REPORT ON INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. 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 for external purposes in accordance with generally accepted accounting principles. Our internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and board of directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

We assessed the effectiveness of our internal control over financial reporting based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in Internal Control Integrated Framework, we have concluded that our internal control over financial reporting was effective as of December 31, 2011. The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included on page 59.

Management of Goodrich Petroleum Corporation

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

Goodrich Petroleum Corporation

We have audited Goodrich Petroleum Corporation and subsidiary s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Goodrich Petroleum Corporation and subsidiary s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Annual Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Goodrich Petroleum Corporation and subsidiary maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2011 consolidated financial statements of Goodrich Petroleum Corporation and subsidiary and our report dated February 24, 2012, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 24, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of

Goodrich Petroleum Corporation

We have audited the accompanying consolidated balance sheets of Goodrich Petroleum Corporation and subsidiary as of December 31, 2011 and 2010, and the related consolidated statements of operations, cash flows, and stockholders equity for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Goodrich Petroleum Corporation and subsidiary at December 31, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Goodrich Petroleum Corporation s internal control over financial reporting as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 24, 2012

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED BALANCE SHEETS

(In Thousands)

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,347	$ 17,788
Restricted cash		4,232
Accounts receivable, trade and other, net of allowance	7,594	9,231
Income taxes receivable	340	4,335
Accrued oil and natural gas revenue	20,420	14,920
Fair value of oil and natural gas derivatives	56,486	24,467
Inventory	8,627	7,831
Prepaid expenses and other	4,315	3,045
Total current assets	101,129	85,849
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	1,542,406	1,217,891
Furniture, fixtures and equipment	5,654	4,962
	1,548,060	1,222,853
Less: Accumulated depletion, depreciation and amortization	(824,894)	(685,110)
Net property and equipment	723,166	537,743
Fair value of oil and natural gas derivatives		15,732
Deferred tax assets	19,720	19,695
Deferred financing cost and other	18,088	5,558
TOTAL ASSETS	$ 862,103	$ 664,577
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 46,095	$ 47,106
Accrued liabilities	43,874	47,105
Accrued abandonment costs	5,176	4,392
Deferred tax liabilities current	19,720	19,695
Current portion of debt		167,086
Total current liabilities	114,865	285,384
LONG-TERM DEBT	566,126	179,171
Accrued abandonment costs	12,249	11,683
Fair value of oil and natural gas derivatives	17,420	4,367
Transportation obligation	7,743	
Total liabilities	718,403	480,605

Commitments and contingencies (See Note 9)		
STOCKHOLDERS EQUITY:		
Preferred stock: 10,000,000 shares authorized:		
Series B convertible preferred stock, $1.00 par value, issued and outstanding 2,250,000	2,250	2,250
Common stock: $0.20 par value, 100,000,000 shares authorized, issued and outstanding 36,378,508 and 37,685,378 shares, respectively	7,276	7,212
Treasury stock (44,826 and 12,377 shares, respectively)	(689)	(196)
Additional paid in capital	641,790	643,828
Retained earnings (accumulated deficit)	(506,927)	(469,122)
Total stockholders equity	143,700	183,972
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 862,103	$ 664,577

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF OPERATIONS

(In Thousands, Except Per Share Amounts)

	Year Ended December 31, 2011	2010	2009
REVENUES:			
Oil and natural gas revenues	$ 200,456	$ 148,031	$ 110,784
Other	613	302	(358)
	201,069	148,333	110,426
OPERATING EXPENSES:			
Lease operating expense	21,490	26,306	30,188
Production and other taxes	5,450	3,627	4,317
Transportation	12,974	9,856	9,459
Depreciation, depletion and amortization	131,811	105,913	160,361
Exploration	8,289	10,152	9,292
Impairment	8,111	234,887	208,905
General and administrative	29,799	30,918	27,923
(Gain) loss on sale of assets	(236)	2,824	(297)
Other	448	4,268	
	218,136	428,751	450,148
Operating loss	(17,067)	(280,418)	(339,722)
OTHER INCOME (EXPENSE):			
Interest expense	(49,351)	(37,179)	(26,148)
Interest income and other	59	117	458
Gain on derivatives not designated as hedges	34,539	55,275	47,115
Gain on extinguishment of debt	62		
	(14,691)	18,213	21,425
Loss before income taxes	(31,758)	(262,205)	(318,297)
Income tax benefit		85	67,311
Net loss	(31,758)	(262,120)	(250,986)
Preferred stock dividends	6,047	6,047	6,047
Net loss applicable to common stock	$ (37,805)	$ (268,167)	$ (257,033)
PER COMMON SHARE			
Net loss applicable to common stock basic	$ (1.05)	$ (7.47)	$ (7.17)
Net loss applicable to common stock diluted	$ (1.05)	$ (7.47)	$ (7.17)
Weighted average common shares outstanding basic	36,124	35,921	35,866
Weighted average common shares outstanding diluted	36,124	35,921	35,866

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In Thousands)

	Year Ended December 31, 2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (31,758)	$ (262,120)	$ (250,986)
Adjustments to reconcile net loss to net cash provided by operating activities Depletion, depreciation and amortization	131,811	105,913	160,361
Unrealized (gain) loss on derivatives not designated as hedges	(3,234)	(31,794)	49,434
Deferred income taxes			(51,845)
Exploration costs			219
Impairment	8,111	234,887	208,905
Amortization of leasehold costs	5,487	5,963	4,927
Share based compensation (non-cash)	6,495	7,554	6,751
(Gain) loss on sale of assets	(236)	2,824	(297)
Gain on extinguishment of debt	(62)		
Amortization of finance cost and debt discount	14,351	19,256	12,221
Amortization of transportation obligation	2,873		
Other non-cash items			282
Change in assets and liabilities:			
Restricted cash	4,232	(4,232)	
Accounts receivable, trade and other, net of allowance	355	(343)	(925)
Income taxes receivable/payable	3,995	11,103	(16,758)
Accrued oil and natural gas revenue	(5,500)	403	(1,611)
Inventory	(796)	(7,169)	102
Prepaid expenses and other	(2,953)	(1,285)	152
Accounts payable	(1,079)	14,571	(6,338)
Accrued liabilities	4,248	4,901	976
Net cash provided by operating activities	136,340	100,432	115,570
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(335,236)	(264,967)	(265,825)
Proceeds from sale of assets	172	64,887	238
Net cash used in investing activities	(335,064)	(200,080)	(265,587)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from high yield offering	275,000		
Repurchase of convertible notes	(176,422)		
Proceeds from bank borrowings	144,500	54,500	5,000
Principal payments of bank borrowings	(42,000)	(54,500)	(80,000)
Debt issuance costs	(9,341)	(492)	(8,755)
Preferred stock dividends	(6,047)	(6,047)	(6,047)
Proceeds from convertible note offering			218,500
Exercise of stock options and warrants		10	26
Other	(1,407)	(1,151)	(1,139)

Net cash provided by (used in) financing activities		184,283		(7,680)		127,585
Decrease in cash and cash equivalents		(14,441)		(107,328)		(22,432)
Cash and cash equivalents, beginning of period		17,788		125,116		147,548
Cash and cash equivalents, end of period	$	3,347	$	17,788	$	125,116
Supplemental disclosures of cash flow information:						
Cash paid during the year for interest	$	35,000	$	18,014	$	12,446
Cash paid during the year for taxes	$		$		$	1,352

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In Thousands)

	Preferred Stock		Common Stock		Additional Paid-in	Treasury Stock		Retained Earnings/	Total Stockholders
	Shares	Value	Shares	Value	Capital	Shares	Value	(Deficit)	Equity
Balance at January 1, 2009	2,250	$ 2,250	37,563	$ 7,188	$ 600,125	(10)	$ (293)	$ 56,078	$ 665,348
Net loss								(250,986)	(250,986)
Capped call option redemption			(266)	(53)					(53)
Equity portion of convertible notes					31,165				31,165
Employee stock plans			139	28	5,991				6,019
Director stock grants			16	3	54				57
Repurchases of stock						(44)	(1,132)		(1,132)
Retirement of stock						34	1,014		1,014
Dividends								(6,047)	(6,047)
Balance at December 31, 2009	2,250	2,250	37,452	7,166	637,335	(20)	(411)	(200,955)	445,385
Net loss								(262,120)	(262,120)
Employee stock plans			282	52	7,502				7,554
Employee stock option exercise				1	9				10
Director stock grants			24	5	301				306
Repurchases of stock				3	(1)	(65)	(1,113)		(1,111)
Retirement of stock			(73)	(15)	(1,313)	73	1,328		
Dividends								(6,047)	(6,047)
Other					(5)				(5)
Balance at December 31, 2010	2,250	$ 2,250	37,685	$ 7,212	$ 643,828	(12)	$ (196)	$ (469,122)	$ 183,972
Net loss								(31,758)	(31,758)
Equity portion of convertible notes redeemed					(7,944)				(7,944)
Employee stock plans			350	70	6,425				6,495
Director stock grants			21	4	385				389
Repurchases of stock						(86)	(1,407)		(1,407)
Retirement of stock			(53)	(10)	(904)	53	914		
Shares returned pursuant to Share Lending Agreement			(1,624)						
Dividends								(6,047)	(6,047)
Balance at December 31, 2011	2,250	$ 2,250	36,379	$ 7,276	$ 641,790	(45)	$ (689)	$ (506,927)	$ 143,700

See accompanying notes to consolidated financial statements.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 Description of Business and Accounting Policies

Goodrich Petroleum Corporation (together with its subsidiary, we, our, or the Company) is an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas on properties primarily in Northwest Louisiana, East Texas and South Texas.

Principles of Consolidation The consolidated financial statements of the Company are included in this Annual Report on Form 10-K have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC) and in accordance with accounting principles generally accepted in the United States (US GAAP). The consolidated financial statements include the financial statements of Goodrich Petroleum Corporation and its wholly-owned subsidiary. Intercompany balances and transactions have been eliminated in consolidation. The consolidated financial statements reflect all normal recurring adjustments that, in the opinion of management, are necessary for a fair presentation. Certain data in prior periods financial statements have been adjusted to conform to the presentation of the current period. We have evaluated subsequent events through the date of this filing.

Use of Estimates Our Management has made a number of estimates and assumptions relating to the reporting of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with US GAAP.

Presentation Change The Consolidated Statement of Operations includes a category of expense titled Interest income and other which includes immaterial effects of discontinued operations from the prior periods. The net effect of discontinued operations is added to this account for the comparative year of 2009.

Cash and Cash Equivalents Cash and cash equivalents include cash on hand, demand deposit accounts and temporary cash investments with maturities of ninety days or less at date of purchase.

Restricted Cash Restricted cash consists of cash held in escrow totaling $4.2 million for the posting of the suspensive appeal bond relating to the *Hoover Tree Farm, LLC v. Goodrich Petroleum Company, LLC, et al*. litigation as of December 31, 2010. None of the cash was restricted as of December 31, 2011. See Note 9.

Allowance for Doubtful Accounts We routinely assess the recoverability of all material trade and other receivables to determine their collectability. Many of our receivables are from a limited number of purchasers. Accordingly, accounts receivable from such purchases could be significant. Generally, our natural gas and crude oil receivables are collected within thirty to sixty days of production. We also have receivables from joint interest owners of properties we operate. We may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

We accrue a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. As of each of December 31, 2011 and 2010, our allowance for doubtful accounts was immaterial.

Inventory Inventory consists of casing and tubulars that are expected to be used in our capital drilling program and oil in storage tanks. Inventory is carried on the Balance Sheet at the lower of cost or market.

Property and Equipment We follow the successful efforts method of accounting for exploration and development expenditures. Under this method, costs of acquiring unproved and proved oil and natural gas leasehold acreage are capitalized. When proved reserves are found on an unproved property, the associated leasehold cost is transferred to proved properties. Significant unproved leases are reviewed periodically, and a

GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

valuation allowance is provided for any estimated decline in value. Costs of all other unproved leases are amortized over the estimated average holding period of the leases. Development costs are capitalized, including the costs of unsuccessful development wells.

Exploration Exploration expenditures, including geological and geophysical costs, delay rentals and exploratory dry hole costs are expensed as incurred. Costs of drilling exploratory wells are initially capitalized pending determination of whether proved reserves can be attributed to the discovery. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are expensed.

Fair Value Measurement Fair value is defined as 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. The fair value of an asset should reflect its highest and best use by market participants, whether in-use or an in-exchange valuation premise. The fair value of a liability should reflect the risk of nonperformance, which includes, among other things, the Company s credit risk.

We use various methods, including the income approach and market approach, to determine the fair values of our financial instruments that are measured at fair value on a recurring basis, which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments into three levels (levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels.

Each of these levels and our corresponding instruments classified by level are further described below:

Level 1 Inputs unadjusted quoted market prices in active markets for identical assets or liabilities.

Level 2 Inputs quotes which are derived principally from or corroborated by observable market data. Included in this level are our long-term debt and our interest rate swaps, if any, and commodity derivatives whose fair values are based on third-party quotes or available interest rate information and commodity pricing data obtained from third party pricing sources and our creditworthiness or that of our counterparties.

Level 3 Inputs unobservable inputs for the asset or liability, such as discounted cash flow models or valuations, based on the Company s various assumptions and future commodity prices. Included in this level are our assets held for sale and oil and natural gas properties which are deemed impaired.

As of December 31, 2011 and 2010, the carrying amounts of our cash and cash equivalents, trade receivables and payables represented fair value because of the short-term nature of these instruments.

Impairment We periodically assess our long-lived assets recorded in oil and natural gas properties on the Consolidated Balance Sheets to ensure that they are not carried in excess of fair value, which is computed using level 3 inputs such as discounted cash flow models or valuations, based on estimated future commodity prices and our various operational assumptions. At least annually or whenever changes in facts and circumstances indicate that our oil and natural gas properties may be impaired; an evaluation is performed on a field-by-field basis.

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GOODRICH PETROLEUM CORPORATION AND SUBSIDIARY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2011, we had interests in oil and natural gas properties totaling $721 million, net of accumulated depletion, which we account for under the successful efforts method. The expected future cash flows used for impairment reviews and related fair-value calculations are based on judgmental assessments of future production volumes, prices, and costs, considering all available information at the date of review. Due to the uncertainty inherent in these factors, we cannot predict when or if additional future impairment charges will be recorded. We estimated future net cash flows generated from our oil and natural gas properties by using forecasted oil and natural gas prices.

We determined during 2011 that the carrying amount of certain of our oil and natural gas properties were not recoverable from future cash flows and, therefore, we recorded an impairment of $8.1 million for the year ended December 31, 2011.

Total impairment associated with our oil and natural gas properties for the years ended December 31, 2010 and 2009 was $234.9 million and $208.9 million, respectively.

Depreciation Depreciation and depletion of producing oil and natural gas properties is calculated using the units-of-production method. Proved developed reserves are used to compute unit rates for unamortized tangible and intangible development costs, and proved reserves are used for unamortized leasehold costs.

Gains and losses on disposals or retirements that are significant or include an entire depreciable or depletable property unit are included in operating income. Depreciation of furniture, fixtures and equipment, consisting of office furniture, computer hardware and software and leasehold improvements, is computed using the straight-line method over their estimated useful lives, which vary from three to five years.

Transportation Obligation We entered into a gas gathering agreement with an independent service provider, effective July 27, 2010. The agreement is scheduled to remain in effect for a period of ten years and requires the service provider to construct pipelines and facilities to connect our wells to the service provider s gathering system in our Eagle Ford Shale area of south Texas. In compensation for the services, we agreed to pay the service provider 110% of the total capital cost incurred by the service provider to construct new pipelines and facilities. The service provider will bill us for 20 percent of the accumulated unpaid capital costs annually.

We accounted for the agreement by recording a long-term asset, included in Deferred financing cost and other on the Consolidated Balance Sheets. The asset is being amortized using the units-of-production method and the amortization expense is included in Transportation on the Consolidated Statements of Operations. The related current and long-term liabilities are presented on the Consolidated Balance Sheets in Accrued liabilities and Transportation obligation , respectively.

Asset Retirement Obligations We follow the accounting standard related to accounting for asset retirement obligations. These obligations are related to the abandonment and site restoration requirements that result from the acquisition, construction and development of our oil and gas properties. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Accretion expense is included in depreciation, depletion and amortization on our Consolidated Statement of Operations.

Revenue Recognition Oil and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues from the production of crude oil and natural gas properties in which we have an interest with other producers are recognized using the entitlements method. We record a liability or an asset for

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natural gas balancing when we have sold more or less than our working interest share of natural gas production, respectively. At December 31, 2011 and 2010, the net liability for natural gas balancing was immaterial. Differences between actual production and net working interest volumes are routinely adjusted.

Derivative Instruments We use derivative instruments such as futures, forwards, options, collars and swaps for purposes of hedging our exposure to fluctuations in the price of crude oil and natural gas and to hedge our exposure to changing interest rates. Accounting standards related to derivative instruments and hedging activities require that all derivative instruments subject to the requirements of those standards be measured at fair value and recognized as assets or liabilities in the balance sheet. Changes in fair value are required to be recognized in earnings unless specific hedge accounting criteria are met. We have not designated any of our derivative contracts as hedges, accordingly; changes in fair value are reflected in earnings.

Income Taxes We account for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We recognize, as required, the financial statement benefit of an uncertain tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

Earnings Per Share Basic income per common share is computed by dividing net income available to common stockholders for each reporting period by the weighted-average number of common shares outstanding during the period. Diluted income per common share is computed by dividing net income available to common stockholders for each reporting period by the weighted average number of common shares outstanding during the period, plus the effects of potentially dilutive stock options and restricted stock calculated using the Treasury Stock method and the potential dilutive effect of the conversion of shares associated with Series B Convertible Preferred Stock, 3.25% Convertible Senior Notes due 2026 and 5% Convertible Senior Notes due 2029.

Commitments and Contingencies Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties, and other sources are recorded when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. Recoveries from third parties, when probable of realization, are separately recorded and are not offset against the related environmental liability.

Concentration of Credit Risk Due to the nature of the industry, we sell our oil and natural gas production to a limited number of purchasers and, accordingly, amounts receivable from such purchasers could be significant. The revenues compared to our total oil and natural gas revenues from the top purchasers for the years ended December 31, 2011, 2010 and 2009 are as follows:

	Year Ended December 31,		
	2011	**2010**	**2009**
Largest purchaser	11%	29%	32%
Second largest purchaser	10%	17%	19%
Third largest purchaser	9%		10%

* The three largest purchasers for 2009, 2010 and 2011 have consisted of different companies each year.

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Share-Based Compensation We account for our share-based transactions using fair value and recognized compensation expense over the requisite service period. The fair value of each option award is estimated using a Black-Scholes option valuation model with various assumptions based on our estimates. Our assumptions include expected volatility, expected term of option, risk-free interest rate and dividend yield. Expected volatility estimates are developed by us based on historical volatility of our stock. We use historical data to estimate the expected term of the options. The risk-free interest rate for periods within the expected life of the option is based on the U.S. Treasury yield in effect at the grant date. Our common stock does not pay dividends; therefore, the dividend yield is zero. The fair value of restricted stock is measured using the close of the day stock price on the day of the award.

Guarantee On March 2, 2011, we issued and sold $275,000,000 aggregate principal amount of our 2019 Notes. The 2019 Notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiary, Goodrich Petroleum Company, L.L.C.

Goodrich Petroleum Corporation, as the parent company (the Parent Company), has no independent assets or operations. The guarantee is full and unconditional, and the Parent Company has no other subsidiaries. In addition, there are no restrictions on the ability of the Parent Company to obtain funds from its subsidiary by dividend or loan. Finally, the Parent Company s wholly-owned subsidiary does not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by the subsidiary without the consent of a third party.

New Accounting Pronouncements

ASU 2010-06 Fair Value Measurements and Disclosures. In January 2010, the Financial Accounting Standards Board (FASB) issued additional guidance on fair value disclosures. The new guidance clarifies two existing disclosure requirements and requires two new disclosures: (1) a gross presentation of activities (purchases, sales, and settlements) within the Level 3 roll-forward reconciliation, which will replace the net presentation format; and (2) detailed disclosures about the transfers in and out of Level 1 and 2 measurements. This guidance is effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll-forward information, which is required for annual reporting periods beginning after December 15, 2010, and for interim reporting periods within those years. The Company adopted the fair value disclosures guidance on January 1, 2010, except for the gross presentation of the Level 3 roll-forward, which was adopted by the Company on January 1, 2011. The adoption of ASU 2010-06 (ASC 820-10) did not have an impact on our financial position, results of operations or cash flows.

ASU 2011-04 Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS In May 2011, the FASB issued additional guidance intended to result in convergence between US GAAP and International Financial Reporting Standards (IFRS) requirements for measurement of and disclosures about fair value. The amendments are not expected to have a significant impact on companies applying US GAAP. Principal provisions of the amendments include: (i) application of the highest and best use is relevant only when measuring fair value for non-financial assets and liabilities, (ii) a prohibition on grouping financial instruments for purposes of determining fair value, except when an entity manages market and credit risks on the basis of the entity s net exposure to the group; (iii) an extension of the prohibition against the use of a blockage factor to all fair value measurements (that prohibition currently applies only to financial instruments with quoted prices in active markets); (iv) guidance that fair value measurement of equity instruments should be made from the perspective of a market participant that holds that instrument as an asset, and (v) a requirement that for recurring Level 3 fair value measurements, entities disclose quantitative information about unobservable inputs, a description of the valuation process used and qualitative details about the sensitivity of the measurements. In addition, for Balance Sheet items not carried at fair value but

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for which fair value is disclosed, entities will be required to disclose the Level within the fair value hierarchy that applies to the fair value measurement disclosed. This guidance is effective for interim and annual periods beginning after December 15, 2011. We will adopt this guidance effective January 1, 2012. The adoption of this guidance is not expected to have an impact on the Company s fair value measurements, financial condition, results of operations or cash flows.

NOTE 2 Share-Based Compensation Plans

Overview

In May 2006, our shareholders approved our 2006 Long-Term Incentive Plan (the 2006 Plan), at our annual meeting of stockholders. The 2006 Plan provides for grants to employees and non-employee directors. Under the 2006 Plan, a maximum of 2.0 million new shares are reserved for issuance as awards of share options to officers, employees and non-employee directors. In May 2011, our shareholders amended the 2006 Plan to increase the maximum number of new shares reserved for issuance as awards of share options to officers, employees and non-employee directors by 2.0 million. As of December 31, 2011, a total of 1,114,309 shares were available for future grants under the 2006 Plan.

The 2006 Plan is intended to promote the interests of the Company, by providing a means by which employees, consultants and directors may acquire or increase their equity interest in the Company and may develop a sense of proprietorship and personal involvement in the development and financial success of the Company, and to encourage them to remain with and devote their best efforts to the business of the Company, thereby advancing the interests of the Company and its stockholders. The 2006 Plan is also intended to enhance the ability of the Company and its Subsidiary to attract and retain the services of individuals who are essential for the growth and profitability of the Company.

The 2006 Plan provides that the Compensation Committee shall have the authority to determine the participants to whom stock options, restricted stock, performance awards, phantom shares and stock appreciation rights may be granted.

We measure the cost of stock based compensation granted, including stock options and restricted stock, based on the fair value of the award as of the grant date, net of estimated forfeitures. Awards granted are valued at fair value and recognized on a straight-line basis over the service periods (or the vesting periods) of each award. We estimate forfeiture rates for all unvested awards based on our historical experience.

The following table summarizes the pretax components of our share-based compensation programs recorded, recognized as a component of general and administrative expenses in the Consolidated Statement of Operations (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Restricted stock expense	$ 6,194	$ 5,944	$ 5,323
Stock option expense	301	1,609	1,428
Director stock expense	525	502	608
Total share-based compensation:	$ 7,020	$ 8,055	$ 7,359

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Stock Options

The 2006 Plan provides that the option price of shares issued be equal to the market price on the date of grant. With the exception of option grants to non-employee directors which vest immediately, options vest ratably on the anniversary of the date of grant over a period of time, typically three years. All options expire ten years after the date of grant.

Option activity under our stock option plans as of December 31, 2011, and changes during the year ended December 31, 2011 were as follows:

	Shares	Weighted Average Exercise Price	Remaining Contractual Term (years)	Aggregate Intrinsic Value (thousands)
Outstanding at January 1, 2011	935,6			