SM Energy Co
Form 10-K
February 23, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
þ 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
o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
Commission file number 001-31539
SM ENERGY COMPANY
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0518430 (I.R.S. Employer Identification No.)
1775 Sherman Street, Suite 1200, Denver, Colorado (Address of principal executive offices)	80203 (Zip Code)

(303) 861-8140
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, $.01 par value	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yesþ Noo

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). Yesþ Noo

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.þ

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

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

The aggregate market value of the 63,229,780 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the Company's common stock on June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter, of $73.48 per share, as reported on the New York Stock Exchange; was $4,646,124,234. Shares of common stock held by each director and executive officer and by each person who owns 10 percent or more of the outstanding common stock or who is otherwise believed by the Company to be in a control position have been excluded. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 16, 2012, the registrant had 64,114,366 shares of common stock outstanding, which is net of 81,067 treasury shares held by the registrant.

DOCUMENTS INCORPORATED BY REFERENCE

Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant's definitive proxy statement relating to its 2012 annual meeting of stockholders to be filed within 120 days after December 31, 2011.

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PART I

When we use the terms "SM Energy," "the Company," "we," "us," or "our," we are referring to SM Energy Company and its subsidiaries unless the context otherwise requires. We have included certain technical terms important to an understanding of our business under Glossary of Oil and Gas Terms. Throughout this document we make statements that may be classified as "forward-looking." Please refer to the Cautionary Information about Forward-Looking Statements section of this document for an explanation of these types of statements.

ITEMS 1. and 2. BUSINESS and PROPERTIES

General

We are an independent energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids (also referred to as "oil", "gas", and "NGLs" throughout the document) in onshore North America, with a current focus on oil and liquids-rich resource plays. We were founded in 1908 and incorporated in Delaware in 1915. Our initial public offering of common stock was in December 1992. Our common stock trades on the New York Stock Exchange under the ticker symbol "SM."

Our principal offices are located at 1775 Sherman Street, Suite 1200, Denver, Colorado 80203, and our telephone number is (303) 861-8140.

Strategy

Our business strategy is focused on the early capture of resource plays in order to create and then enhance value for our shareholders, while maintaining a strong balance sheet. We strive to leverage industry leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have captured potential value through these efforts, our goal is to develop such potential through top tier operational and project execution. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to improve our returns and preserve our financial strength.

Significant Developments in 2011

- Resource Play Delineation and Development Results in Record Production and Increase in Year-End Proved Reserve Estimates. Our estimated proved reserves increased 28 percent to 1,259.2 BCFE at December 31, 2011, from 984.5 BCFE at December 31, 2010. We added 526.1 BCFE through drilling activity during the year, which was primarily led by our efforts in the Eagle Ford shale in South Texas, the Bakken/Three Forks plays in North Dakota, and the Haynesville shale in East Texas. We achieved record levels of production in 2011. Our average daily production was composed of 274.8 MMcf of gas, 22.1 MBbl of oil, and 9.6 MBbl of NGLs for an average equivalent production rate of 465.0 MMCFE per day, which was an increase of 54 percent from 301.4 MMCFE per day in 2010. Costs incurred in 2011 for drilling and exploration activities and acquisitions increased 77 percent, to $1.6 billion, compared with $877.4 million in 2010. The increase in capital investment reflects increased confidence in our drilling inventory, particularly in plays with significant oil and NGL-rich gas components, such as our Eagle Ford shale and Bakken/Three Forks plays. Please refer to Core Operational Areas below for additional discussion concerning our 2011 estimated proved reserves, production, and capital investment.
- Acquisition and Development Agreement. In December 2011, we closed on our Acquisition and Development Agreement with Mitsui E&P Texas LP ("Mitsui"), an indirect subsidiary of Mitsui & Co. Ltd., which transferred 12.5 percent of our working interest in certain non-operated oil and gas assets in South Texas. Under the agreement, Mitsui agreed to pay, or carry, 90 percent of certain drilling and completion costs for wells targeting the Eagle Ford shale attributable to our remaining interests in these assets, until Mitsui has expended an aggregate of $680.0 million on our behalf. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement in Part II, Item 8 of this report for additional discussion concerning this transaction.
- Financing Activities. During 2011, our financing activities consisted of the following transactions:

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- issuance of $350.0 million in aggregate principal amount of 6.625% Senior Notes due 2019 ("6.625% Senior Notes");
- issuance of $350.0 million in aggregate principal amount of 6.50% Senior Notes due 2021 ("6.50% Senior Notes"); and
- execution of a $2.5 billion Fourth Amended and Restated Credit Agreement with a borrowing base of $1.3 billion and lender commitments of $1.0 billion, as of December 31, 2011.

Please refer to Note 5 - Long-term Debt in Part II, Item 8 of this report for additional discussion regarding our financing arrangements.

- Impairments. We recognized $219.0 million of proved property impairments for the year ended December 31, 2011. A significant decrease in natural gas prices during the second half of 2011 led to the impairment of certain dry gas assets in our ArkLaTex region.
- Divestiture Activity. We continuously look to improve the quality of our asset portfolio through the divestiture of non-strategic properties. Our divestiture activity helps to generate cash that can be used to fund the development of assets with higher potential value and for other general corporate purposes. Often, but not always, we divest of properties with higher operating costs and/or limited future drilling or development potential. During 2011, we sold 93.1 BCFE of reserves, the majority of which related to assets located in our South Texas & Gulf Coast region. The following transactions represent our most significant divestitures during 2011:
- Eagle Ford Shale Divestiture. In August 2011, we completed the divestiture of certain operated Eagle Ford shale assets located in our South Texas & Gulf Coast region. This position comprised our entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of our operated acreage in Dimmit County, Texas. Total divestiture proceeds, before marketing costs, Net Profits Interest Bonus Plan ("Net Profits Plan") payments, and legal fees (referred to subsequently as "divestiture proceeds"), were $230.8 million. The estimated gain on this divestiture was $194.6 million and post-closing adjustments, if any, are expected to be finalized in the first quarter of 2012.
- Mid-Continent Divestiture. In June 2011, we completed the divestiture of certain non-strategic assets located in our Mid-Continent region. Total divestiture proceeds were $35.8 million. The estimated gain on this divestiture was $28.5 million and post-closing adjustments, if any, are expected to be finalized in the first quarter of 2012.
- Rocky Mountain Divestiture. In January 2011, we completed the divestiture of certain non-strategic assets located in our Rocky Mountain region. Total divestiture proceeds were $45.5 million. The final gain on this divestiture was $27.2 million.

Outlook for 2012

We enter 2012 with a capital program expected to be in the range of approximately $1.4 billion to $1.5 billion, of which approximately $1.2 billion to $1.3 billion will be allocated to drilling and completion activities focused primarily on the development of our inventory of resource play opportunities. Please refer to Core Operational Areas below for detailed discussion of our 2012 capital budget by region and Outlook for 2012 under Part II, Item 7 of this report for additional discussion surrounding our capital plans for 2012.

As we enter 2012, we are well positioned both financially and operationally. From a financial perspective, we believe that we are adequately capitalized and have sufficient liquidity to fund our planned capital expenditures for this year. Operationally, we have secured the majority of the drilling rigs and services required to execute our 2012 business plan.

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Core Operational Areas

Our operations are concentrated in five core operating areas in the onshore United States. The following table summarizes estimated proved reserves, PV-10 reserve value, and production for the year ended December 31, 2011, for our core operating areas:

	ArkLaTex	Mid-Continent	South Texas & Gulf Coast	Permian	Rocky Mountain	Total[1]
Proved Reserves						
Oil (MMBbl)	0.3	0.8	14.6	12.4	43.7	71.7
Gas (Bcf)	124.0	223.9	243.0	31.7	41.5	664.0
NGLs (MMBbl)	0.9	1.0	25.5	0.2	—	27.5
Equivalents (BCFE)	130.6	234.6	483.6	107.0	303.4	1,259.2
Relative percentage	10 %	19 %	38 %	9 %	24 %	100 %
Proved Developed %	76 %	75 %	54 %	86 %	71 %	67 %
PV-10 Values (in millions) [2]						
Proved Developed	$173.7	$353.9	$857.7	$459.8	$991.2	$2,836.3
Proved Undeveloped [3]	16.9	42.3	294.5	51.4	219.8	624.9
Total Proved	$190.6	$396.2	$1,152.2	$511.2	$1,211	$3,461.2
Relative percentage	6 %	11 %	33 %	15 %	35 %	100 %
Production						
Oil (MMBbl)	0.1	0.4	2.6	1.3	3.7	8.1
Gas (Bcf)	29.3	28.6	34.7	3.5	4.2	100.3
NGLs (MMBbl)	0.1	0.1	3.2	—	—	3.5
Equivalent (BCFE)	30.1	31.6	69.7	11.5	26.7	169.7
Avg. Daily Equivalents (MMCFE/d)	82.5	86.7	191.1	31.5	73.3	465.0
Relative percentage	18 %	19 %	41 %	6 %	16 %	100 %

(1) Totals may not sum due to rounding.

(2) The standardized measure PV-10 calculation is presented in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown in the Reserves section below.

(3) We record estimates of proved undeveloped reserves for locations with a positive PV-0 value when we have the intent to drill the location and it meets our economic criteria.

South Texas & Gulf Coast Region. Operations for the South Texas & Gulf Coast region are managed from our office in Houston, Texas. Our current operations in this region focus primarily on our Eagle Ford shale program. Our acreage position covers a significant portion of the western Eagle Ford shale play, including acreage in the oil, the NGL-rich gas, and the dry gas windows of the play. We entered 2011 with approximately 250,000 net acres in the play, which was comprised of an approximate 165,000 net acre operated position in Webb, Dimmit, and LaSalle Counties, Texas and an approximate 85,000 net acre non-operated position in Maverick, Dimmit, LaSalle, and Webb Counties, Texas. During the year we reduced our acreage in two separate transactions. The first transaction was a sale of approximately 15,400 net operated acres in LaSalle and Dimmit Counties, Texas to Talisman Energy USA Inc. and Statoil Texas Onshore Properties LLC (collectively, "Talisman/Statoil") for $225.0 million, which closed in August 2011. The second transaction, which reduced our working interest from approximately 27.0 percent to approximately 14.5 percent, was our assignment of approximately 39,000 net acres in our non-operated program to Mitsui in exchange for Mitsui's agreement to carry 90 percent of our drilling and completion costs until Mitsui has expended $680.0 million for our benefit. This transaction closed in December 2011. These two transactions allowed us to consolidate our operating foot print in the play and, by divesting of a significant piece of our non-operated program, put a greater percentage of our capital expenditures in this play under our operational control. As of December 31, 2011, we have roughly 196,000 net acres in the play.

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Approximately 75 percent of this acreage is operated by us with an average working interest of nearly 100 percent. On our operated acreage position, we increased our rig count over the course of the year from two rigs at the beginning of the year to five drilling rigs by year end. During the year, we also increased our contracted firm transportation capacity for our operated wet gas volumes to approximately 225 MMcf from approximately 100 MMcf. In 2012, our firm transportation capacity will continue to increase, which we expect will allow us to exit the year with approximately 270 MMcf of gross wet gas firm transportation capacity. In our non-operated Eagle Ford shale program, the operator of the program increased its rig count from seven at the beginning of 2011 to ten by year-end. We participated in substantially all of the drilling activity in the non-operated Eagle Ford shale program during the year. Additionally, we participated as a co-owner in the construction of midstream assets that service our non-operated acreage in the play.

Nearly all of our capital deployed in the South Texas & Gulf Coast region in 2011 targeted our Eagle Ford shale program. Our capital investment, production, and reserves all increased significantly in 2011 as a result of our focused efforts in our Eagle Ford shale program, which has become a critical growth driver of production and reserve growth for the Company. Our capital expenditures for exploration, development, and acquisition activities in our South Texas & Gulf Coast region increased significantly from $456.2 million in 2010 to $932.3 million in 2011. Production in 2011 was 69.7 BCFE, an increase of 207 percent over the 22.7 BCFE produced in 2010. Estimated proved reserves at the end of 2011 increased 133 percent to 483.6 BCFE from 207.3 BCFE in the prior year, while reflecting the reduction of 70.2 BCFE of proved reserves as a result of our transactions with Mitsui and Talisman/Statoil. Of the reserve additions in the region, approximately 353.3 BCFE of proved reserves were added through drilling activities. The increase in production and proved reserves reflects the significant increase in activity in our Eagle Ford shale program throughout the year.

Our plan for 2012 in the South Texas & Gulf Coast region is to continue focusing primarily on the Eagle Ford shale. At the beginning of 2012, we had five operated rigs, two of which are designed for pad drilling. We expect to operate five to six drilling rigs throughout 2012, with an increasing number of those rigs being capable of pad drilling. We believe that we have sufficient access to drilling rigs and completion services to execute our plan for the year. A significant portion of the gas takeaway capacity we will need for 2012 has been secured under firm transportation contracts. In the non-operated portion of our Eagle Ford shale position, the operator has indicated that it plans to operate approximately ten drilling rigs throughout 2012.

We have allocated a range of $650 million to $700 million of our 2012 capital budget to our operated Eagle Ford shale drilling program. Most of our drilling and completion costs in the non-operated portion of our Eagle Ford shale program will be carried by Mitsui during 2012 under the terms of our Acquisition and Development Agreement with Mitsui, although we will be responsible for our proportionate share of any infrastructure investments made in this program.

Rocky Mountain Region. Operations for our Rocky Mountain region are managed from our office in Billings, Montana. Our capital expenditures in 2011 primarily targeted the Bakken/Three Forks formations in the North Dakota portion of the Williston Basin, where we have approximately 87,000 net acres. In 2011, we were successful in testing prospects farther west and north of our prior development activity in North Dakota. In our Raven and Bear Den prospects, our efforts have largely centered on optimizing our completions and spacing for development of the Bakken formation. In our Gooseneck prospect in Divide County, North Dakota, our efforts have been focused on the Three Forks formation. Elsewhere in the Rocky Mountain region, we drilled several test wells in the Niobrara formation in Wyoming during the year. At year-end 2011, we had 91,000 net acres with potential for the Niobrara and other formations in the northern DJ and Powder River Basins.

Our capital expenditures for exploration, development, and acquisition activity in our Rocky Mountain region increased from $158.5 million in 2010 to $288.0 million in 2011, as we accelerated our activity in the Bakken/Three Forks formations and commenced testing of our Niobrara acreage. Estimated proved reserves for our Rocky Mountain region were 303.4 BCFE at year-end 2011, compared with 231.8 BCFE as of the end of 2010, a 31 percent increase over 2010. During the year, we added approximately 105.3 BCFE of proved reserves through drilling activities. Our program targeting the Bakken/Three Forks formations contributed the majority of our proved reserve additions in this region. Total regional production for 2011 was up seven percent to 26.7 BCFE,

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despite weather related delays throughout the region, including unusually severe spring flooding and wet weather which hindered production and drilling activity through the summer. As these issues subsided, we were able to increase activity and complete most of our planned activity for the year.

Our capital budget for operated Bakken/Three Forks activity in 2012 is a range of $160 million and $185 million. We expect to operate four rigs in the play, up from three rigs at the end of 2011. Our drilling activity will be focused on holding our acreage in the Raven and Gooseneck prospects and will also include infill wells in our Bear Den prospect along the Nesson Anticline. We also expect to participate in a number of Bakken/Three Forks projects with other operators. In addition to Bakken/Three Forks drilling, we plan to split one operated rig between our two prospect areas located in the northern DJ Basin and the Powder River Basin in Wyoming.

Mid-Continent Region. Operations for our Mid-Continent region are managed from our office in Tulsa, Oklahoma. Our current operations in the Mid-Continent region are primarily focused on the horizontal development of the Granite Wash formation in western Oklahoma. Our Mid-Continent region also manages our Woodford shale assets, on which we have minimized activity due to the low natural gas price environment. Our 2011 Granite Wash program targeted the shallower, more NGL-rich washes of our approximate 29,000 net acres in the play, the majority of which is held by production. In 2011, we incurred costs of $87.8 million in the Mid-Continent region for exploration, development, and acquisition activity, which is a 30 percent decrease from the $124.5 million incurred in 2010 for the region. In 2011, our Mid-Continent region's production was 31.6 BCFE, a decrease from the 33.4 BCFE produced in 2010. Proved reserves at the end of 2011 were 234.6 BCFE, a decrease of 20 percent from the 293.7 BCFE reported for 2010.

We plan to invest between $60 million and $70 million in 2012 in our operated horizontal Granite Wash program, with three operated drilling rigs planned to execute our drilling program for the year. No meaningful activity is required or expected in our Woodford shale program in 2012 due to our current outlook for natural gas prices. However, an increase in natural gas prices or a decrease in the costs of drilling and completing these wells could result in increased activity in the Woodford shale program.

ArkLaTex Region. Operations for our ArkLaTex region have historically been managed from our office in Shreveport, Louisiana. In the second half of 2011, we began consolidating our ArkLaTex and Mid-Continent regional offices into our office in Tulsa, Oklahoma. Our recent focus of the ArkLaTex region has been the horizontal development of our Haynesville shale acreage and achieving held by production status on our operated acreage position in East Texas. From a strategic standpoint, we believe holding this acreage, which is prospective for the Haynesville and Bossier shales, will provide value for us in the future if the economics for natural gas improve.

In 2011, we incurred costs of $159.2 million in the ArkLaTex region for exploration, development, and acquisition activity, which is a 234 percent increase from the $47.6 million incurred in 2010 for the region and is a result of our significant increase in capital expenditures in our operated Haynesville shale program to achieve held by production status. In 2011, production in our ArkLaTex region was 30.1 BCFE, a 109 percent increase from the 14.4 BCFE produced in 2010. Proved reserves at the end of 2011 were 130.6 BCFE, a decrease from the 137.9 BCFE reported for the prior year.

With the recent decline in natural gas prices, we have reduced our planned level of operated drilling activity in the Haynesville shale. Several operated wells that were previously planned for have been cut from the drilling schedule and we now expect to only invest between $35 million and $40 million on operated Haynesville shale drilling in 2012. This will result in the forfeiture of a small amount of operated acreage. After completing currently planned activity, we think that nearly 80 percent of our Haynesville acreage will be held by production, and we then plan to limit activity until gas prices recover or drilling costs lessen to a point that drilling projects meet our internal economic hurdles.

Permian Region. Operations for our Permian region are managed from our office in Midland, Texas. Our Permian region covers western Texas and eastern New Mexico. Our primary area of development focus in this region is the

Wolfberry tight oil play, and we are actively working to delineate a newer exploratory play targeting

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the Mississippian limestone play.
We incurred costs of $80.7 million in the region for exploration, development, and acquisition activity in 2011 compared to $85.4 million in 2010. During the year, downspacing activity continued across our Wolfberry acreage. In addition, during 2011 we began testing acreage in Lynn, Borden, and Garza Counties, Texas targeting the vertical and horizontal development of the Mississippian limestone play. The region’s 2011 production was 11.5 BCFE, a decrease from 2010 production of 14.7 BCFE. The decrease in production was due to natural decline in the Wolfberry play as the field development matured and the number of remaining drilling locations on our acreage decreased. Proved reserves in this region as of the end of 2011 were 107.0 BCFE, which was a slight decline from 2010 year-end reserves of 113.9 BCFE.
During 2012, we plan to focus our Permian investment on further delineation of the Mississippian limestone play. A portion of our remaining capital allocated to this region will be spent on the development of our Wolfberry acreage.

Reserves
The table below presents summary information with respect to the estimates of our proved reserves for each of the years in the three-year period ended December 31, 2011. We engaged Ryder Scott Company, L.P. (“Ryder Scott”) to audit internal engineering estimates for at least 80 percent of the PV-10 value of our estimated proved reserves in each year presented. The prices used in the calculation of proved reserve estimates as of December 31, 2011, were $96.19 per Bbl for oil, $4.12 per MMBtu for natural gas, and $59.37 per Bbl for NGLs.
We emphasize that reserve estimates are inherently imprecise and that reserve estimates for new discoveries and undeveloped locations are more imprecise than reserve estimates for producing oil and gas properties. Accordingly, these estimates are expected to change as new information becomes available. The PV-10 values shown in the following table are not intended to represent the current market value of the estimated proved reserves owned by us. Neither prices nor costs have been escalated. The following table should be read along with the section entitled Risk Factors – Risks Related to Our Business contained herein. The actual quantities and present values of our estimated proved reserves may be less than we have estimated. No estimates of our proved reserves have been filed with or included in reports to any federal authority or agency, other than the SEC, since the beginning of the last fiscal year.
Our ability to replace our production is important to our sustainability. Please refer to the reserve replacement terms in the Glossary of Oil and Gas Terms section of this report for information describing how our reserve replacement metrics are calculated. Our reserve replacement percentages are calculated using information from the Oil and Gas Reserve Quantities section of Supplemental Oil and Gas Information located in Part II, Item 8 of this report.

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We believe the concept of reserve replacement as described in the Glossary of Oil and Gas Terms section of this report, as well as permutations which may include other captions of the Oil and Gas Reserve Quantities section of Supplemental Oil and Gas Information located in Part II, Item 8 of this report, are widely understood by those who make investment decisions related to the oil and gas exploration business.

	As of December 31,					
	2011		2010		2009	
Reserve data:						
Proved developed						
Oil (MMBbl)	50.3		46.0		48.1	
Gas (Bcf)	451.2		411.0		342.0	
NGLs (MMBbl)	15.2		-		-	
BCFE	844.0		687.3		630.3	
Proved undeveloped						
Oil (MMBbl)	21.4		11.4		5.7	
Gas (Bcf)	212.8		229.0		107.5	
NGLs (MMBbl)	12.3		-		-	
BCFE	415.2		297.2		141.9	
Total Proved						
Oil (MMBbl)	71.7		57.4		53.8	
Gas (Bcf)	664.0		640.0		449.5	
NGLs (MMBbl)	27.5		-		-	
BCFE	1,259.2		984.5		772.2	
Proved developed reserves %	67	%	70	%	82	%
Proved undeveloped reserves %	33	%	30	%	18	%
Reserve value data (in millions):						
Proved developed PV-10	$2,836.3		$2,053.5		$1,253.1	
Proved undeveloped PV-10	624.9		290.8		31.0	
Total proved PV-10	$3,461.2		$2,344.3		$1,284.1	
Standardized measure of discounted future cash flows	$2,580.0		$1,666.4		$1,016.0	
Reserve replacement – drilling , excluding revisions	310	%	349	%	100	%
All in – including sales of reserves	262	%	293	%	14	%
All in – excluding sales of reserves	317	%	372	%	55	%
Reserve life (years) (1)	7.4		8.9		7.1	

(1) Reserve life represents the estimated proved reserves at the dates indicated divided by actual production for the preceding 12-month period.

Note: NGL reserve data, production volumes, revenues, and prices for prior periods have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices under Part II, Item 7 of this report.

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The following table reconciles the standardized measure of discounted future net cash flows (GAAP) to the PV-10 value (Non-GAAP). The difference is a result of the PV-10 value measure excluding the impact of income taxes. Please see the definitions of standardized measure of discounted future net cash flows and PV-10 value in the Glossary of Oil and Gas Terms.

	As of December 31,		
	2011	2010	2009
	(in millions)		
Standardized measure of discounted future net cash flows	$2,580.0	$1,666.4	$1,016.0
Add: 10 percent annual discount, net of income taxes	1,727.6	1,294.6	733.0
Add: future undiscounted income taxes	1,740.4	1,335.5	515.9
Undiscounted future net cash flows	$6,048.0	$4,296.5	$2,264.9
Less: 10 percent annual discount without tax effect	(2,586.8)	(1,952.2)	(980.8)
PV-10 value	$3,461.2	$2,344.3	$1,284.1

Proved Undeveloped Reserves

As of December 31, 2011, we had 415.2 BCFE of proved undeveloped reserves, which is an increase of 118.0 BCFE, or 40 percent, over proved undeveloped reserves of 297.2 BCFE at December 31, 2010. We added 202.2 BCFE of proved undeveloped reserves through our drilling program, 187.5 BCFE of which were extensions and discoveries, primarily in the Eagle Ford shale and the Bakken/Three Forks plays, as well as an additional 14.7 BCFE of infill proved undeveloped reserves that were mostly concentrated in our assets in the Bakken/Three Forks formations, the Eagle Ford shale, and in our Wolfberry properties in our Permian region. A negative price revision of 33.4 BCFE was primarily due to gas weighted projects in our ArkLaTex and Mid-continent regions that no longer met internal economic investment hurdles for projects in which we would invest due to lower natural gas prices or that no longer generate positive cash flow utilizing 12-month average benchmark pricing required by the SEC. We had a net positive performance revision of 8.5 BCFE, which includes the impact of our conversion to three stream production reporting, as well as negative engineering revisions due primarily to higher than expected well costs in the Woodford shale in our Mid-Continent region, causing those projects to no longer meet our internal investment hurdles. During the year, we sold assets comprising 24.5 BCFE from our South Texas & Gulf Coast region. We invested $86.2 million to convert 34.6 BCFE of proved undeveloped reserves to proved reserves in 2011, mainly in the Eagle Ford and Haynesville shales and the Bakken/Three Forks formations.

As of December 31, 2011, we had no material proved undeveloped reserves that have been on our books in excess of five years, and we had recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. As of December 31, 2011, estimated future development costs relating to our proved undeveloped reserves are approximately $285 million, $289 million, and $266 million in 2012, 2013, and 2014, respectively.

Internal Controls Over Reserves Estimate

Our internal controls over the recording of proved reserves are structured to objectively and accurately estimate our reserve quantities and values in compliance with the SEC's regulations. Our process for managing and monitoring the Company's proved reserves is delegated to our reservoir engineering group, which is managed by Dennis A. Zubieta, our Vice President - Engineering and Evaluation, subject to the oversight of our management and the Audit Committee of our Board of Directors, as discussed below.

Mr. Zubieta joined us in June 2000 as a Corporate Acquisition & Divestiture Engineer, assumed the role of Reservoir Engineer in February 2003, was appointed Reservoir Engineering Manager in August 2005, and was

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appointed Vice President - Engineering and Evaluation in August 2008. Mr. Zubieta was employed by Burlington Resources Oil and Gas Company from June 1988 to May 2000 in various operations and reservoir engineering capacities. Mr. Zubieta received a Bachelor of Science degree in Petroleum Engineering from Montana Tech in May 1988. Technical reviews are performed throughout the year by regional staff who evaluate geological and engineering data. This data, in conjunction with economic data and our ownership information, is used in making a determination of estimated proved reserve quantities. The regional technical staff does not report directly to Mr. Zubieta; they report to either regional technical managers or directly to the regional manager in their respective regions. This is intended to promote objective and independent analysis, within our regions as part of the reserves estimation process.

Third-party Reserves Audit

An independent audit is performed by Ryder Scott using their own engineering assumptions and economic and ownership data provided by us. A minimum of 80 percent of our total calculated proved reserve PV-10 value is audited by Ryder Scott. In the aggregate, the proved reserve values of our audited properties are required to be within ten percent of our valuations for the total company as well as for each respective region. Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum engineering consulting services throughout the world for over seventy years. The technical person at Ryder Scott primarily responsible for overseeing our reserve audit is a Senior Vice President, who received a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970 and who is a registered Professional Engineer in Colorado and Utah. He is also a member of the Society of Petroleum Engineers. The Ryder Scott 2011 report concerning our reserves is included as Exhibit 99.1.

In addition to a third party audit, our reserves are reviewed by management and the Audit Committee of our Board of Directors. Management, which includes the President and Chief Executive Officer, the Executive Vice President and Chief Operating Officer, and the Executive Vice President and Chief Financial Officer, is responsible for reviewing and verifying that the estimate of proved reserves is reasonable, complete, and accurate. The Audit Committee reviews the final reserves estimate in conjunction with Ryder Scott’s audit report. They may also meet with Ryder Scott representatives to discuss its processes and findings.

Production

The following table summarizes the volumes and realized prices of oil, gas, and NGLs produced from properties in which we held an interest during the periods indicated. Realized prices presented below exclude the effects of hedges and derivative contracts. Also presented is a summary of production costs per MCFE:

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	Years Ended December 31,		
	2011	2010	2009
Net production[1]			
Oil (MMBbl)	8.1	6.4	6.3
Gas (Bcf)	100.3	71.9	71.1
NGLs (MMBbl)	3.5	—	—
BCFE	169.7	110.0	109.1
Average net daily production[1]			
Oil (MBbl per day)	22.1	17.4	17.3
Gas (MMcf per day)	274.8	196.9	194.8
NGLs (MBbl per day)	9.6	—	—
MMCFE per day	465.0	301.4	298.8
Realized price			
Oil (per Bbl)	$88.23	$72.65	$54.40
Gas (per Mcf)	$4.32	$5.21	$3.82
NGLs (per Bbl)	$53.32	$—	$—
Per MCFE	$7.85	$7.60	$5.65
Production costs per MCFE			
Lease operating expense	$0.88	$1.10	$1.33
Transportation costs	$0.51	$0.19	$0.19
Production taxes	$0.32	$0.48	$0.37

(1) In 2011 and 2010, total estimated proved reserves for our Eagle Ford shale properties equated to greater than 15 percent of our total proved reserves expressed on an equivalent basis. During 2011, our net production from the Eagle Ford shale was 32.9 Bcf of gas, 2.5 MMBbl of oil, and 3.1 MMBbl of NGLs or 66.6 BCFE. Our average daily production from the Eagle Ford shale was 90.1 MMcf of gas, 6.8 MBbl of oil, and 8.6 MBbl of NGLs, for an average production rate of 182.5 MMCFE per day. During 2010, our net production from the Eagle Ford shale was 13.0 Bcf of gas and 0.8 MMBbl of oil, or 17.6 BCFE. Our average daily production from the Eagle Ford shale was 35.6 MMcf of gas and 2.1 MBbl of oil, for an average production rate of 48.3 MMCFE per day. No fields contained 15 percent or greater of our total proved reserves expressed on an equivalent basis in 2009.

Note: NGL reserve data, production volumes, revenues, and prices for prior periods have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion under the caption Oil, Gas, and NGL Prices under Part II, Item 7 of this report.

Productive Wells

As of December 31, 2011, we had working interests in 1,353 gross (741 net) productive oil wells and 2,928 gross (1,060 net) productive gas wells. Productive wells are either wells producing in commercial quantities or wells mechanically capable of commercial production, but are currently shut-in. Multiple completions in the same wellbore are counted as one well. A well is categorized under state reporting regulations as an oil well or a gas well based on the ratio of gas to oil produced when it first commenced production, and such designation may not be indicative of current production.

Drilling Activity

All of our drilling activities are conducted using independent drilling contractors. We do not own any drilling equipment. The following table summarizes the number of operated and non-operated wells drilled and recompleted on our properties in 2011, 2010, and 2009, excluding any wells in which we own only a royalty interest:

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	Years Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	125	32.1	191	36.5	103	29.6
Gas	273	81.0	72	17.0	74	18.2
Non-productive	11	4.0	4	1.1	3	1.3
	409	117.1	267	54.6	180	49.1
Exploratory wells:						
Oil	16	6.3	36	11.5	2	0.4
Gas	48	8.6	83	37.9	18	9.1
Non-productive	3	1.0	1	0.8	5	2.9
	67	15.9	120	50.2	25	12.4
Total	476	133.0	387	104.8	205	61.5

A productive well is an exploratory, development, or extension well that is producing oil, gas, and/or NGLs or that is capable of commercial production of those products. A dry well (hole) is an exploratory, development, or extension well that proves to be incapable of producing either oil, gas, and/or NGLs in commercial quantities.

As defined by the SEC, an 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. A development well is a well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive and is part of a development project, which is defined as the means by which petroleum resources are brought to economically producible status. The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for production of oil, gas, and/or NGLs, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

In addition to the wells drilled and completed in 2011 included in the table above, as of February 16, 2012, we were participating in the drilling of 34 gross wells. We operate 12 of these wells on a gross basis, seven on a net basis, with the remaining 22 gross wells, four on a net basis, being operated by others. With respect to completion activity, at such date, there were 156 gross wells in which we have an interest that were being completed. We operate 28 of these completion activities on a gross basis, 16 on a net basis, and were participating in 128 gross, 18 net non-operated completion activities. The vast majority, if not all, of these operations relate to the drilling of wells for primary production.

Acreage

The following table sets forth the gross and net acres of developed and undeveloped oil and gas leasehold, fee properties, and mineral servitudes held by us as of December 31, 2011. Undeveloped acreage includes leasehold interests that may already be classified as containing proved undeveloped reserves.

	Developed Acres [1]		Undeveloped Acres [2]		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	70,632	26,049	16,367	4,716	86,999	30,765
Montana	59,071	40,655	315,582	212,371	374,653	253,026
Nevada	-	-	197,634	197,634	197,634	197,634
North Dakota	134,647	88,865	158,543	87,186	293,190	176,051
Oklahoma	257,348	82,962	39,280	14,334	296,628	97,296
Pennsylvania	346	346	49,676	39,749	50,022	40,095
Texas	211,525	135,211	489,922	226,543	701,447	361,754
Wyoming	62,936	28,305	304,603	166,371	367,539	194,676
Other [3]	4,430	2,011	53,418	34,351	57,848	36,362
	800,935	404,404	1,625,025	983,255	2,425,960	1,387,659
Louisiana Fee Properties	10,499	10,499	14,415	14,415	24,914	24,914
Louisiana Mineral Servitudes	7,426	4,217	4,769	4,407	12,195	8,624
	17,925	14,716	19,184	18,822	37,109	33,538
Total [4]	818,860	419,120	1,644,209	1,002,077	2,463,069	1,421,197

(1) Developed acreage is acreage assigned to producing wells for the state approved spacing unit for the producing formation. Our developed acreage that includes multiple formations with different well spacing requirements may be considered undeveloped for certain formations, but have only been included as developed acreage in the presentation above.

(2) Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

(3) Includes interest in Arkansas, Colorado, Illinois, Kansas, Mississippi, New Mexico, and Utah.

(4) As of the filing date, we had approximately 50,000, 73,000, and 65,000 net acres scheduled to expire by December 31, 2012, 2013, and 2014, respectively, if production is not established or we take no other action to extend the terms.

Delivery Commitments

As of December 31, 2011, we had gathering, processing, and transportation through-put commitments with various parties that require us to deliver a fixed determinable quantity of product. We have an aggregate minimum commitment to deliver 1,766 Bcf of natural gas and 9 MMBbls of oil. These contracts expire at various dates through 2023. We will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. If a shortfall in the minimum volume commitment for natural gas is projected, we have certain rights to arrange for third party gas to be delivered into the gathering lines and such volume will count towards our minimum commitment. At the current time, we do not have enough proved developed reserves to offset these contractual liabilities, but we expect to fulfill the delivery commitments with production from development of our proved reserves, as well as the development of resources not yet characterized as proved reserves, from our Eagle Ford shale and Haynesville shale resource plays. Therefore, we currently do not expect any shortfalls.

Major Customers

During 2011 and 2010, sales to Regency Gas Services LLC ("Regency") individually accounted for approximately 18 percent and 11 percent, respectively, of our total oil, gas, and NGL production revenue. During 2009, sales to Teppco Crude Oil LLC individually accounted for 12 percent of our total oil and gas production revenue.

Employees and Office Space

As of February 16, 2012, we had 639 full-time employees. None of our employees are subject to a collective bargaining agreement, and we consider our relations with our employees to be good. As of December 31, 2011, we leased approximately 84,000 square feet of office space in Denver, Colorado for our executive and administrative offices; approximately 39,000 square feet of office space in Tulsa, Oklahoma;

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approximately 30,000 square feet in Houston, Texas; approximately 30,000 square feet in Billings, Montana; approximately 25,000 square feet in Shreveport, Louisiana; approximately 22,000 square feet in Midland, Texas; approximately 7,000 total square feet in Williston and Watford City, North Dakota; and approximately 2,000 square feet in Casper, Wyoming.

Title to Properties

Substantially all of our interests are held pursuant to leases from third parties. A title opinion is usually obtained prior to the commencement of initial drilling operations. We have obtained title opinions or have conducted a title review on substantially all of our producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. The majority of our producing properties are subject to mortgages securing indebtedness under our credit facility, royalty interests, liens for current taxes, and other burdens that we believe do not materially interfere with the use of, or affect the value of, such properties. We typically perform only minimal title investigation before acquiring undeveloped leasehold acreage.

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during winter months and decrease during summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies, and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are impacted more significantly by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. The impact of seasonality on oil has been somewhat magnified by overall supply and demand economics attributable to the narrow margin of worldwide production capacity in excess of existing worldwide demand for oil. Certain of our drilling and completion operations are also subject to seasonal limitations. Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate. See Risk Factors - Risks Related to Our Business for additional discussion.

Competition

The oil and gas industry is intensely competitive, particularly with respect to acquiring prospective oil and natural gas properties. We believe our leasehold position provides a sound foundation for a solid drilling program and our future growth. Our competitive position also depends on our geological, geophysical, and engineering expertise, as well as our financial resources. We believe the location of our acreage; our exploration, drilling, operational, and production expertise; available technologies; our financial resources and expertise; and the experience and knowledge of our management and technical teams enable us to compete in our core operating areas. However, we face intense competition from a substantial number of major and independent oil and gas companies, which in some cases have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs and other equipment, and generate electricity.

We also compete with other oil and gas companies in attempting to secure drilling rigs and other equipment and services necessary for the drilling, completion, and maintenance of wells. Consequently, we may face shortages or delays in securing these services from time to time. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may be affected by future new energy, climate-related, financial, and/or other policies, legislation, and regulations.

In addition, we compete for people, including experienced geologists, geophysicists, engineers, and other

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professionals. Throughout the oil and gas industry, the need to attract and retain talented people has grown at a time when the availability of individuals with these skills is becoming more limited due to demographics in our industry. We are not insulated from the competition for quality people, and we must compete effectively in order to be successful.

Government Regulations

Our business is extensively regulated by numerous federal, state, and local laws and governmental regulations. These laws and regulations may be changed from time to time in response to economic or political conditions, or other developments, and our regulatory burden may increase in the future. Laws and regulations have the potential of increasing our cost of doing business and, consequently, could affect our profitability. However, we do not believe that we are affected to a materially greater or lesser extent than others in our industry.

Energy Regulations. Many of the states in which we conduct our operations have adopted laws and regulations governing the exploration for and production of oil, gas, and NGLs, including laws and regulations requiring permits for the drilling of wells, imposing bonding requirements in order to drill or operate wells, and governing the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the plugging and abandonment of wells. Our operations are also subject to various state conservation laws and regulations, including regulations governing the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, the spacing of wells, and the unitization or pooling of oil and gas properties. In addition, state conservation laws sometimes establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas, and may impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Some of our operations are conducted on federal lands pursuant to oil and gas leases administered by the Bureau of Land Management ("BLM"). These leases contain relatively standardized terms and require compliance with detailed regulations and orders, which are subject to change. In addition to permits required from other regulatory agencies, lessees must obtain a permit from the BLM before drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, the valuation of production and payment of royalties, the removal of facilities, and the posting of bonds to ensure that lessee obligations are met. Under certain circumstances, the BLM may suspend or terminate our operations on federal leases. In May 2010, the BLM adopted changes to its oil and gas leasing program that require, among other things, a more detailed environmental review prior to leasing oil and natural gas resources, increased public engagement in the development of master leasing and development plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process. These changes may increase the amount of time and regulatory costs necessary to obtain oil and gas leases administered by the BLM.

Our sales of gas are affected by the availability, terms, and cost of gas pipeline transportation. The Federal Energy Regulatory Commission ("FERC") has jurisdiction over the transportation and sale for resale of gas in interstate commerce. FERC's current regulatory framework generally provides for a competitive and open access market for sales and transportation of natural gas. However, FERC regulations continue to affect the midstream and transportation segments of the industry, and thus can indirectly affect the sales prices we receive for gas production. In addition, the less stringent regulatory approach currently pursued by FERC and the United States Congress may not continue indefinitely.

Environmental, Health and Safety Matters

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

- require the acquisition of various permits before drilling commences;

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, including areas containing certain wildlife or threatened and endangered plant and animal species; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

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

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

Waste handling. The Resource Conservation and Recovery Act (the "RCRA") and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas 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, or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

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Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States and states. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. Army Corps of Engineers or analogous state agencies. 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.

The Oil Pollution Act of 1990 ("OPA") addresses prevention, containment and cleanup, and liability associated with oil pollution. OPA applies to vessels, offshore platforms, and onshore facilities. OPA subjects owners of such facilities to strict liability for containment and removal costs, natural resource damages and certain other consequences of oil spills into jurisdictional waters. Any unpermitted release of petroleum or other pollutants from our operations could result in governmental penalties and civil liability.

Air emissions. The federal Clean Air Act ("CAA"), and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. Legislative and regulatory initiatives related to climate change could have an adverse effect on our operatives and the demand for oil and gas. See "Risk Factors - Risks Related to Our Business - Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for oil, gas and NGLs." In addition to the effects of regulation, the meteorological effects of global climate change could pose additional risks to our operations, including physical damage risks associated with more frequent, more intensive storms and flooding, and could adversely affect the demand for our products.

Endangered species. The federal Endangered Species Act and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our well drilling operations are conducted in areas where protected species are known to exist. 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 drilling 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 drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete well drilling and development and could adversely affect our future production from those areas.

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

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OSHA and other laws and regulation. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's Underground Injection Control Program. The federal Safe Drinking Water Act protects the quality of the nation's public drinking water through the adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas activities using hydraulic fracturing techniques which could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and delays which could adversely affect our financial position, results of operations and cash flows. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We cannot give any assurance that we will not be adversely affected in the future.

Cautionary Information about Forward-Looking Statements

This Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events, or developments with respect to our financial condition, results of operations, or economic performance that we expect, believe, or anticipate will or may occur in the future, or that address plans and objectives of management for future operations, are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar ex
intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-K, and include statements about such matters as:

- the amount and nature of future capital expenditures and the availability of liquidity and capital resources to fund capital expenditures;
- the drilling of wells and other exploration and development activities and plans, as well as possible future acquisitions;
- the possible divestiture or farm-down of, or joint venture relating to, certain properties;

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- proved reserve estimates and the estimates of both future net revenues and the present value of future net revenues associated with those proved reserve estimates;
- future oil, gas, and NGL production estimates;
- our outlook on future oil, gas, and NGL prices, well costs, and service costs;
- cash flows, anticipated liquidity, and the future repayment of debt;
- business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations or to defer capital investment, and our outlook on our future financial condition or results of operations; and
- other similar matters such as those discussed in the Management's Discussion and Analysis of Financial Condition and Results of Operations section in Item 7 of this report.

Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties, which may cause our actual results and performance to be materially different from any future results or performance expressed or implied by the forward-looking statements. These risks are described in the Risk Factors section of this report, and include such factors as:

- the volatility of oil, gas, and NGL prices, and the effect it may have on our profitability, financial condition, cash flows, access to capital, and ability to grow production volumes and/or proved reserves;
- the continued weakness in economic conditions and uncertainty in financial markets;
- our ability to replace reserves in order to sustain production;
- our ability to raise the substantial amount of capital that is required to replace our reserves;
- our ability to compete against competitors that have greater financial, technical, and human resources;
- our ability to attract and retain key personnel;
- the imprecise estimations of our actual quantities and present value of proved oil, gas, and NGL reserves;
- the uncertainty in evaluating recoverable reserves and estimating expected benefits or liabilities;
- the possibility that exploration and development drilling may not result in commercially producible reserves;
- our limited control over activities on non-operated properties;
- our reliance on the skill and expertise of third-party service providers on our operated properties;
- the possibility that title to properties in which we have an interest may be defective;
- the possibility that our planned drilling in existing or emerging resource plays using some of the latest available horizontal drilling and completion techniques is subject to drilling and completion risks and may not meet our expectations for reserves or production;

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- the uncertainties associated with divestitures, joint ventures, farm-downs, farm-outs and similar transactions with respect to certain assets, including whether such transactions will be consummated or completed in the form or timing and for the value that we anticipate;
- the uncertainties associated with enhanced recovery methods;
- our commodity derivative contracts may result in financial losses or may limit the prices that we receive for oil, gas, and NGL sales;
- the inability of one or more of our vendors, customers, or contractual counterparties to meet their obligations;
- price declines or unsuccessful exploration efforts resulting in write-downs of our asset carrying values;
- the impact that lower oil, gas, or NGL prices could have on our ability to borrow under our credit facility;
- the possibility that our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt;
- operating and environmental risks and hazards that could result in substantial losses;
- complex laws and regulations, including environmental regulations, that result in substantial costs and other risks;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities;
- our ability to sell and/or receive market prices for our oil, gas, and NGLs;
- new technologies may cause our current exploration and drilling methods to become obsolete;
- the possibility of security threats, including terrorist attacks and cybersecurity breaches, against, or otherwise impacting, our facilities and systems; and
- litigation, environmental matters, the potential impact of government regulations, and the use of management estimates regarding such matters.

We caution you that forward-looking statements are not guarantees of future performance and that actual results or performance may be materially different from those expressed or implied in the forward-looking statements. The forward-looking statements in this report speak as of the filing date of this report. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.

Available Information

Our internet website address is www.sm-energy.com. We routinely post important information for investors on our website. Within our website’s investor relations section we make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed with or furnished to the SEC under applicable securities laws. These materials are made available as soon as reasonably practical after we electronically file such materials with or furnish such materials to the SEC. We also make available through our website’s corporate governance section our Corporate Governance Guidelines, Code of Business Conduct and Ethics, and the Charters for our Board of Directors’ Audit Committee, Compensation Committee, Executive Committee, and Nominating and Corporate Governance Committee. Information on our

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website is not incorporated by reference into this report and should not be considered part of this document.

Glossary of Oil and Gas Terms

The oil and gas terms defined in this section are used throughout this report. The definitions of the terms developed reserves, exploratory well, field, proved reserves, and undeveloped reserves have been abbreviated from the respective definitions under SEC Rule 4-10(a) of Regulation S-X, as amended effective for fiscal years ending on or after December 31, 2009. The entire definitions of those terms under Rule 4-10(a) of Regulation S-X can be located through the SEC's website at www.sec.gov.

Bbl. One stock tank barrel, or 42 U.S. gallons of liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet, used in reference to natural gas.

BCFE. Billion cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

BOE. Barrels of oil equivalent. Oil equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

BTU. One British thermal unit, the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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

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

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

Dry hole. A well found to be incapable of producing either oil, natural gas, and/or NGLs in commercial quantities.

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

Fee properties. The most extensive interest that can be owned in land, including surface and mineral (including oil and natural gas) rights.

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

Finding and development cost. Expressed in dollars per MCFE. Finding and development cost metrics provide information as to the cost of adding proved reserves from various activities, and are widely utilized within the exploration and production industry, as well as by investors. The information used to calculate these metrics is included in the Supplemental Oil and Gas Information section in Part II, Items 8 of this report. It should be noted that finding and development cost metrics have limitations. For example, exploration efforts related to a particular set of proved reserve additions may extend over several years. As a result, the exploration costs incurred in earlier periods are not included in the amount of exploration costs incurred during the period in which that set of proved reserves is added. In addition, consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred. Since the additional development costs that will need to be incurred in

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the future before the proved undeveloped reserves are ultimately produced are not included in the amount of costs incurred during the period in which those reserves were added, those development costs in future periods will be reflected in the costs associated with adding a different set of reserves. The calculations of various finding and development cost metrics are explained below.

Finding and development cost – Drilling, excluding revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, and infill drilling, during the same period.

Finding and development cost – Drilling, including revisions. Calculated by dividing the amount of costs incurred for development and exploration activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and revisions of previous estimates, during the same period.

Finding and development cost – Drilling and acquisitions, excluding revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, and acquisitions, during the same period.

Finding and development cost – Drilling and acquisitions, including revisions. Calculated by dividing the amount of costs incurred for development, exploration, and acquisition of proved properties, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, revisions of previous estimates, and acquisitions, during the same period.

Finding and development cost –All in, including sales of reserves. Calculated by dividing the amount of total capital expenditures for oil and natural gas activities, by the amount of estimated net proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of previous estimates less sales of reserves, during the same period.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Gross acre. An acre in which a working interest is owned.

Gross well. A well in which a working interest is owned.

Horizontal wells. Wells that are drilled at angles greater than 70 degrees from vertical.

Lease operating expenses. The expenses incurred in the lifting of crude oil, natural gas, and/or associated liquids from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, maintenance, allocated overhead costs, and other expenses incidental to production, but not including lease acquisition, drilling, or completion costs.

MBbl. One thousand barrels of crude oil or other liquid hydrocarbons.

MMBbl. One million barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet, used in reference to natural gas.

MCFE. One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

MMcf. One million cubic feet, used in reference to natural gas.

MMCFE. One million cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil or NGLs.

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MMBtu. One million British thermal units.
Net acres or net wells. Sum of our fractional working interests owned in gross acres or gross wells.
Net asset value per share. The result of the fair market value of total assets less total liabilities, divided by the total number of outstanding shares of common stock.
NGLs. The combination of ethane, propane, butane, and natural gasolines that when removed from natural gas become liquid under various levels of higher pressures and lower temperatures.
NYMEX WTI. New York Mercantile Exchange West Texas Intermediate.
OPIS. Oil Price Information Service Mont Belvieu.
PV-10 value (Non-GAAP). The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, based on prices used in estimating the proved reserves and costs in effect as of the date indicated (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expenses, or depreciation, depletion, and amortization, discounted using an annual discount rate of ten percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies and from period to period. This is a Non-GAAP measure.
Productive well. A well that is producing crude oil, natural gas, and/or NGLs or that is capable of commercial production of those products.
Proved reserves. Those quantities of oil, gas, and NGLs which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
Recompletion. The completion in an existing wellbore in a formation other than that in which the well has previously been completed.
Reserve life. Expressed in years, represents the estimated net proved reserves at a specified date divided by actual production for the preceding 12-month period.
Reserve replacement. Reserve replacement metrics are used as indicators of a company's ability to replenish annual production volumes and grow its reserves, and provide information related to how successful a company is at growing its proved reserve base. These are believed to be useful non-GAAP measures that are widely utilized within the exploration and production industry, as well as by investors. They are easily calculable metrics, and the information used to calculate these metrics is included in the Supplemental Oil and Gas Information section of Part II, Item 8 of this report. It should be noted that reserve replacement metrics have limitations. They are limited because they typically vary widely based on the extent and timing of new discoveries and property acquisitions. Their predictive and comparative value is also limited for the same reasons. In addition, because the metrics do not embed the cost or timing of future production of new reserves, they cannot be used as a measure of value creation.

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The calculations of various reserve replacement metrics are explained below.
Reserve replacement – Drilling, excluding revisions. Calculated as a numerator comprised of the sum of reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.
Reserve replacement – Drilling, including revisions. Calculated as a numerator comprised of the sum of reserve extensions, discoveries, and infill reserves, and revisions of previous estimates in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling activity.
Reserve replacement – Drilling and acquisitions, excluding revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions and discoveries and infill reserves in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.
Reserve replacement – Drilling and acquisitions, including revisions. Calculated as a numerator comprised of the sum of reserve acquisitions and reserve extensions, discoveries, and infill reserves, and revisions of previous estimates in an existing proved field divided by production for that same period. This metric is an indicator of the relative success a company is having in replacing its production through drilling and acquisition activities.
Reserve replacement percentage – All in, excluding sales of reserves. The sum of reserve extensions and discoveries, infill drilling, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.
Reserve replacement percentage –All in, including sales of reserves. The sum of sales of reserves, infill drilling, reserve extensions and discoveries, reserve acquisitions, and reserve revisions of previous estimates for a specified period of time divided by production for that same period.
Reservoir. A porous and permeable underground formation containing a natural accumulation of producible crude oil, natural gas, and/or associated liquid resources that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Resource play. A term used to describe an accumulation of crude oil, natural gas, and/or associated liquid resources known to exist over a large areal expanse, which when compared to a conventional play typically has a lower expected geological and/or commercial development risk.
Royalty. The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil, natural gas, and NGLs produced and sold unencumbered by expenses relating to the drilling, completing, and operating of the affected well.
Royalty interest. An interest in an oil and natural gas property entitling the owner to shares of crude oil, natural gas, and NGL production free of costs of exploration, development, and production operations.
Seismic. The sending of energy waves or sound waves into the earth and analyzing the wave reflections to infer the type, size, shape, and depth of subsurface rock formations.
Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.
Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a ten percent

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annual discount rate. The information for this calculation is included in the supplemental information regarding disclosures about oil and gas producing activities following the Notes to Consolidated Financial Statements included in this report.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil, gas, and/or NGLs regardless of whether such acreage contains estimated net proved reserves.

Undeveloped reserves. 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. 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.

Working interest. The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production, sales, and costs.

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ITEM 1A. RISK FACTORS

In addition to the other information included in this report, the following risk factors should be carefully considered when evaluating an investment in us.

Risks Related to Our Business

Crude oil, natural gas, and NGL prices are volatile, and declines in prices adversely affect our profitability, financial condition, cash flows, access to capital, and ability to grow.

Our revenues, operating results, profitability, future rate of growth, and the carrying value of our oil and natural gas properties depend heavily on the prices we receive for crude oil, natural gas and NGL sales. Crude oil, natural gas, and NGL prices also affect our cash flows available for capital expenditures and other items, our borrowing capacity, and the amount and value of our crude oil, natural gas, and NGL reserves. For example, the amount of our borrowing base under our credit facility is subject to periodic redeterminations based on crude oil, natural gas, and NGL prices specified by our bank group at the time of redetermination. In addition, we may have crude oil and natural gas property impairments or downward revisions of estimates of proved reserves if prices fall significantly.

Historically, the markets for crude oil, natural gas, and NGLs have been volatile, and they are likely to continue to be volatile. Wide fluctuations in crude oil, natural gas, and NGL prices may result from relatively minor changes in the supply of and demand for crude oil, natural gas, and NGLs, market uncertainty, and other factors that are beyond our control, including:

- global and domestic supplies of crude oil, natural gas, and NGLs, and the productive capacity of the industry as a whole;
- the level of consumer demand for crude oil, natural gas, and NGLs;
- overall global and domestic economic conditions;
- weather conditions;
- the availability and capacity of gathering, transportation, processing, and/or refining facilities in regional or localized areas that may affect the realized price for crude oil, natural gas, or NGLs;
- the price and level of foreign imports of crude oil, refined petroleum products, and liquefied natural gas;
- the price and availability of alternative fuels;
- technological advances affecting energy consumption;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain crude oil price and production controls;
- political instability or armed conflict in crude oil or natural gas producing regions;
- strengthening and weakening of the United States dollar relative to other currencies; and
- governmental regulations and taxes.

These factors and the volatility of crude oil, natural gas, and NGL markets make it extremely difficult to predict future crude oil, natural gas, and NGL price movements with any certainty. Declines in crude oil, natural gas, and NGL prices would reduce our revenues and could also reduce the amount of crude oil, natural gas, and

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NGLs that we can produce economically, which could have a materially adverse effect on us.

Continued weakness in economic conditions or uncertainty in financial markets may have material adverse impacts on our business that we cannot predict.

United States and global economies and financial systems have recently experienced turmoil and upheaval characterized by extreme volatility and declines in prices of securities, diminished liquidity and credit availability, inability to access capital markets, the bankruptcy, failure, collapse, or sale of financial institutions, increased levels of unemployment, and an unprecedented level of intervention by the United States federal government and other governments. Although some portions of the economy appear to have stabilized and there have been signs of the beginning of a recovery, the extent and timing of a recovery, and whether it can be sustained, are uncertain. Continued weakness in the United States or other large economies could materially adversely affect our business and financial condition. For example:

- the demand for crude oil, natural gas, and NGLs in the United States has declined and may remain at low levels or further decline if economic conditions remain weak, and continue to negatively impact our revenues, margins, profitability, operating cash flows, liquidity, and financial condition;
- natural gas prices have recently been lower than at various times in the last decade because of increased supply resulting from, among other things, increased drilling in unconventional reservoirs, reduced demand in connection with the recent recession, and an unusually warm winter, which sustained low prices could affect our financial condition and results of operations;
- the tightening of credit or lack of credit availability to our customers could adversely affect our ability to collect our trade receivables;
- the liquidity available under our credit facility could be reduced if any lender is unable to fund its commitment;
- our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital for our business, including for exploration and/or development of our reserves;
- our commodity derivative contracts could become economically ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection; and
- variable interest rate spread levels, including for LIBOR and the prime rate, could increase significantly, resulting in higher interest costs for unhedged variable interest rate based borrowings under our credit facility.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop, or acquire crude oil, natural gas, and NGL reserves that are economically producible. Our properties produce crude oil, natural gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new crude oil, natural gas, and NGL reserves to replace those being depleted by production. In addition, competition for crude oil and natural gas properties is intense and many of our competitors have financial, technical, human, and other resources needed to evaluate and integrate acquisitions that are substantially greater than those available to us.

In the event we do complete an acquisition, its successful impact on our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price, future crude oil, natural gas, and NGL prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation and development activities on the acquired properties, and future abandonment and

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possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Without successful drilling or acquisition activities, our reserves and production will decline over time. Substantial capital is required to replace our reserves.

We must make substantial capital expenditures to find, acquire, develop, and produce crude oil, natural gas, and NGL reserves. Future cash flows and the availability of financing are subject to a number of factors, such as the level of production from existing wells, prices received for crude oil, natural gas, and NGL sales, our success in locating and developing and acquiring new reserves, and the orderly functioning of credit and capital markets. If crude oil, natural gas, and NGL prices decrease or if we encounter operating difficulties that result in our cash flows from operations being less than expected, we must reduce our capital expenditures unless we can raise additional funds through debt or equity financing or the divestment of assets. Debt or equity financing may not always be available to us in sufficient amounts or on acceptable terms, and the proceeds offered to us for potential divestitures may not always be of acceptable value to us.

If our revenues decrease due to lower crude oil, natural gas, or NGL prices, decreased production, or other reasons, and if we cannot obtain capital through our credit facility, other acceptable debt or equity financing arrangements, or through the sale of assets, our ability to execute development plans, replace our reserves, maintain our acreage, or maintain production levels could be greatly limited.

Competition in our industry is intense, and many of our competitors have greater financial, technical, and human resources than we do.

We face intense competition from major oil and gas companies, independent oil and natural gas exploration and production companies, financial buyers, and institutional and individual investors who seek crude oil and natural gas property investments throughout the world, as well as the equipment, expertise, labor, and materials required to operate crude oil and natural gas properties. Many of our competitors have financial, technical, and other resources vastly exceeding those available to us, and many crude oil and natural gas properties are sold in a competitive bidding process in which our competitors may be able and willing to pay more for development prospects and productive properties, or in which our competitors have technological information or expertise that is not available to us to evaluate and successfully bid for the properties. In addition, shortages of equipment, labor, or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring and developing profitable properties in the face of this competition.

We also compete for human resources. Over the last few years, the need for talented people across all disciplines in the industry has grown, while the number of talented people available has not grown at the same pace, and in many cases, is declining due to the demographics of the industry.

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The loss of key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

The actual quantities and present value of our proved crude oil, natural gas, and NGL reserves may be less than we have estimated.

This report and other of our SEC filings contain estimates of our proved crude oil, natural gas, and NGL reserves and the estimated future net revenues from those reserves. These estimates are based on various assumptions, including assumptions required by the SEC relating to crude oil, natural gas, and NGL prices, drilling and completion costs, operating expenses, capital expenditures, taxes, timing of operations, and availability of funds. The process of estimating crude oil, natural gas, and NGL reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir. These estimates are dependent on many variables, and therefore changes often occur as our knowledge of these variables evolve. Therefore, these estimates are inherently imprecise. In addition, the reserve estimates we make for fields that do not have a lengthy production history may be less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates, and the timing of development expenditures.

Actual future production, prices for crude oil, natural gas, and NGLs, revenues, production taxes, development expenditures, operating expenses, and quantities of producible crude oil, natural gas, and NGL reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities of and present value related to proved reserves disclosed by us, and the actual quantities and present value may be less than we have previously estimated. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development activity, prevailing crude oil, natural gas, and NGL prices, costs to develop and operate properties, and other factors, many of which are beyond our control. Our properties may also be susceptible to hydrocarbon drainage from production on adjacent properties.

As of December 31, 2011, 33 percent, or 415.2 BCFE, of our estimated proved reserves were proved undeveloped, and four percent, or 54.3 BCFE, were proved developed non-producing. In order to develop our proved undeveloped reserves, as of December 31, 2011, we estimate approximately $939 million of capital expenditures would be required. Production revenues from proved developed non-producing reserves will not be realized until sometime in the future and after some investment of capital. In order to bring production on-line for our proved developed non-producing reserves, as of December 31, 2011, we estimate capital expenditures of approximately $41 million will be deployed in future years. Although we have estimated our proved reserves and the costs associated with these proved reserves in accordance with industry standards, estimated costs may not be accurate, development may not occur as scheduled, and actual results may not occur as estimated. A significant portion of our anticipated capital expenditures for 2012 is directed toward projects that are not yet classified within the construct of proved reserves as defined by Regulation S-X promulgated by the SEC.

You should not assume that the PV-10 value and standardized measure of discounted future net cash flows included in this report represent the current market value of our estimated proved crude oil, natural gas, and NGL reserves. Management has based the estimated discounted future net cash flows from proved reserves on price and cost assumptions required by the SEC, whereas actual future prices and costs may be materially higher or lower. For example, values of our reserves as of December 31, 2011, were estimated using a calculated 12-month average sales price of $4.12 per MMBtu of natural gas (NYMEX Henry Hub spot price), $96.19 per Bbl of oil (NYMEX WTI spot price), and $59.37 per Bbl of NGL (OPIS spot price). We then adjust these base prices to reflect appropriate basis, quality, and location differentials over that period in estimating our proved reserves. During

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2011, our monthly average realized natural gas prices, excluding the effect of derivative cash settlements, were as high as $4.79 per Mcf and as low as $3.58 per Mcf. For the same period, our monthly average realized crude oil prices before the effect of derivative cash settlements were as high as $104.75 per Bbl and as low as $78.95 per Bbl, and were as high as $75.57 per Bbl and as low as $41.14 per Bbl for NGLs. Many other factors will affect actual future net cash flows, including:

- amount and timing of actual production;
- supply and demand for crude oil, natural gas, and NGLs;
- curtailments or increases in consumption by oil purchasers and natural gas pipelines; and
- changes in government regulations or taxes, including severance and excise taxes.

The timing of production from oil and natural gas properties and of related expenses affects the timing of actual future net cash flows from proved reserves, and thus their actual present value. Our actual future net cash flows could be less than the estimated future net cash flows for purposes of computing the PV-10 value. In addition, the ten percent discount factor required by the SEC to be used to calculate the PV-10 value for reporting purposes is not necessarily the most appropriate discount factor given actual interest rates, costs of capital, and other risks to which our business and the oil and natural gas industry in general are subject.

Proved reserve estimates as of December 31, 2011, 2010, and 2009 have been prepared under the SEC's new rules for oil and gas reporting that were effective for fiscal years ending on or after December 31, 2009. These new rules require SEC reporting companies to prepare their proved reserve estimates using, among other things, revised reserve definitions and revised pricing based on 12-month unweighted first-day-of-the-month average pricing, instead of the prior requirement to use pricing at the end of the period. The SEC has released only limited interpretive guidance regarding reporting of proved reserve estimates under the new rules and may not issue further interpretive guidance on the new rules in the near future. The interpretation of these rules and their applicability in different situations remains unclear in many respects. Changing interpretations of the rules or disagreements with our interpretations could result in revisions to our proved reserve estimates, which could be significant.

Another impact of the SEC rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling programs. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill on those reserves within the required five-year timeframe. Substantial downward adjustments to our estimated proved reserves could have a material adverse effect on our financial condition, results of operations, and operating cash flows.

Our property acquisitions may not be worth what we paid due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors sometimes beyond our control. These factors include exploration potential, future crude oil, natural gas, and NGL prices, operating costs, and potential environmental and other liabilities. These assessments are not precise and their accuracy is inherently uncertain.

In connection with our acquisitions, we typically perform a customary review of the acquired properties that will not necessarily reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties.

In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such acquisitions may be limited.

Integrating acquired properties and businesses involves a number of other special risks, including the risk that management may be distracted from normal business concerns by the need to integrate operations and systems as well as retain and assimilate additional employees. Therefore, we may not be able to realize all of the anticipated benefits of our acquisitions.

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

Some of our properties, including a portion of our operations in the Eagle Ford shale in South Texas, are operated by other companies and involve third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including the nature and timing of drilling and operational activities, the operator's skill and expertise, compliance with environmental, safety and other regulations, the approval of other participants in such properties, the selection and application of suitable technology, or the amount of capital expenditures that we will be required to fund with respect to such properties. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs and materially and adversely affect our financial condition and results of operations.

We rely on third-party service providers to conduct the drilling operations on properties we operate.

Where we are the operator of a property, we rely on third-party service providers to perform the necessary drilling operations. The ability of third-party service providers to perform such drilling operations will depend on those service providers' ability to compete for and retain qualified personnel, financial condition, economic performance, and access to capital, which in turn will depend upon the supply and demand for oil, natural gas liquids and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the property and adversely affect our financial condition and results of operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally rely on title reports in acquiring oil and gas leasehold interests and obtain title opinions only on significant properties that we drill. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Title insurance is not available for oil and gas properties. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and title abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. Generally, under the terms of the operating agreements affecting our properties, any monetary loss attributable to a loss of title is to be borne by all parties to any such agreement in proportion to their interests in such property. A material title defect can reduce the value or render a property worthless, thus adversely affecting our financial condition, results of operations and operating cash flow if such property is of sufficient value.

Exploration and development drilling may not result in commercially producible reserves.

Crude oil and natural gas drilling and production activities are subject to numerous risks, including the risk that no commercially producible crude oil, natural gas, or associated liquids will be found. The cost of drilling and

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completing wells is often uncertain, and crude oil, natural gas or associated liquids drilling and production activities may be shortened, delayed, or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- title problems;
- disputes with owners or holders of surface interests on or near areas where we operate;
- pressure or geologic irregularities in formations;
- engineering and construction delays;
- equipment failures or accidents;
- hurricanes or other adverse weather conditions;
- compliance with environmental and other governmental requirements; and
- shortages or delays in the availability of or increases in the cost of drilling rigs and crews, fracture stimulation crews and equipment, pipe, chemicals, water, sand, and other supplies.

The prevailing prices for crude oil, natural gas, and NGLs affect the cost of and the demand for drilling rigs, completion and production equipment, and other related services. However, changes in costs may not occur simultaneously with corresponding changes in commodity prices. The availability of drilling rigs can vary significantly from region to region at any particular time. Although land drilling rigs can be moved from one region to another in response to changes in levels of demand, an undersupply of rigs in any region may result in drilling delays and higher drilling costs for the rigs that are available in that region. In addition, the recent economic and financial downturn has adversely affected the financial condition of some drilling contractors, which may constrain the availability of drilling services in some areas.

Another significant risk inherent in our drilling plans is the need to obtain drilling permits from state, local, and other governmental authorities. Delays in obtaining regulatory approvals and drilling permits, including delays that jeopardize our ability to realize the potential benefits from leased properties within the applicable lease periods, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a materially adverse effect on our ability to explore on or develop our properties.

The wells we drill may not be productive and we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well if crude oil, natural gas, or NGLs are present, or whether they can be produced economically. The cost of drilling, completing, and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Drilling activities can result in dry holes or wells that are productive but do not produce sufficient net revenues after operating and other costs to cover initial drilling and completion costs.

Drilling results in our newer shale plays, such as the Eagle Ford and Haynesville shales, may be more uncertain than results in shale plays that are more developed and have longer established production histories. For example, our experience with horizontal drilling in these shales, as well as the industry's drilling and production history, is more limited than in many shale plays, such as the Barnett or Woodford shales, and we and the industry generally have less information with respect to the ultimate recoverability of reserves and the production decline rates in these shales than other areas with longer histories of drilling and production. Completion techniques that have proven to be successful in other shale formations to maximize recoveries are being used in the early development of these new shales; however, we can provide no assurance of the ultimate success of these drilling

and completion techniques.
In addition, a significant part of our strategy involves increasing our inventory of drilling locations. Such multi-year drilling inventories can be more susceptible to long-term uncertainties that could materially alter the occurrence or timing of actual drilling. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled, although we have the present intent to do so, or if we will be able to produce crude oil, natural gas, or NGLs from these or any other potential drilling locations.
Our future drilling activities may not be successful. Our overall drilling success rate or our drilling success rate within a particular area may decline. In addition, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified numerous potential drilling locations, we may not be able to economically produce oil or natural gas from all of them.
Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory and delineation drilling in these plays are subject to drilling and completion technique risks, and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.
Many of our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore, and being able to run tools and recover equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools and other equipment the entire length of the well bore during completion operations, being able to recover such tools and other equipment, and successfully cleaning out the well bore after completion of the final fracture stimulation.
Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or prices for crude oil, natural gas, and NGL decline, then the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of oil and gas properties and the value of our undeveloped acreage could decline in the future.
Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.
We inject water into formations on some of our properties to increase the production of crude oil, natural gas, and associated liquids. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of crude oil, natural gas, and associated liquids in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. In addition, if proposed legislation and regulatory initiatives relating to hydraulic fracturing become law, the cost of some of these enhanced recovery methods could increase substantially.
Our commodity derivative contract activities may result in financial losses or may limit the prices that we receive for crude oil, natural gas, and NGL sales.
To mitigate a portion of the exposure to potentially adverse market changes in crude oil, natural gas, and

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NGL prices and the associated impact on cash flows, the Company has entered into various derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for crude oil, natural gas, and NGLs. As of December 31, 2011, we were in a net accrued asset position of $31.2 million with respect to our crude oil, natural gas, and NGL derivative activities. These activities may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected;
- one or more counterparties to our commodity derivative contracts default on their contractual obligations; or
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the commodity derivative contract arrangement.

The risk of one or more counterparties defaulting on their obligations is heightened by the recent global and domestic economic and financial downturn affecting many banks and other financial institutions, including our counterparties and their affiliates. These circumstances may adversely affect the ability of our counterparties to meet their obligations to us pursuant to derivative transactions, which could reduce our revenues and cash flows from realized derivative cash settlements. As a result, our financial condition, results of operations, and cash flows could be materially affected in an adverse way if our counterparties default on their contractual obligations under our commodity derivative contracts.

In addition, commodity derivative contracts may limit the prices that we receive for our crude oil, natural gas and NGL sales if crude oil, natural gas, or NGL prices rise substantially over the price established by the commodity derivative contract.

The inability of customers or co-owners of assets to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from crude oil, natural gas, and NGL sales or joint interest billings to co-owners of oil and gas properties we operate. This concentration of customers and joint interest owners may impact our overall credit risk because these entities may be similarly affected by various economic and other conditions, including the recent global and domestic economic and financial downturn.

In addition, for the year ended December 31, 2011, one customer, Regency, individually accounted for approximately 18 percent of our total production revenue. During 2010 and 2009, we had one customer each year, Regency and Teppco Crude Oil LLC, individually account for approximately 11 percent and 12 percent, respectively, of our total production revenue. The loss of one or more of these customers could reduce competition for our products and negatively impact the prices at which we sell such products.

We have entered into firm transportation contracts that require us to pay fixed amounts of money to our counterparties regardless of quantities actually shipped, processed, or gathered. If we are unable to deliver the necessary quantities of natural gas to our counterparties, our results of operations and liquidity could be adversely affected.

As of December 31, 2011, we were contractually committed to deliver 1,766 Bcf of natural gas and 9 MMbl of oil pursuant to contracts expiring at various dates through 2023. We may enter into additional firm transportation agreements as our development of our shale plays, including the Eagle Ford and Haynesville shales, expand. At the current time, we do not have enough proved developed reserves to offset these contractual liabilities, but we intend to develop reserves that will exceed the commitments and therefore do not expect any shortfalls. We expect our production volumes, as well as that of our competitors, to increase significantly in the Eagle Ford shale. The use of firm transportation commitments gives us the strategic advantage of priority space in a transportation pipeline. In the event we encounter delays in drilling and completing our wells or otherwise due to construction, interruptions of

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operations, or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, the requirements to pay for quantities not delivered could have a material impact on our results of operations and liquidity.

Future crude oil, natural gas, and NGL price declines or unsuccessful exploration efforts may result in write-downs of our asset carrying values.

We follow the successful efforts method of accounting for our crude oil and natural gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If commercial quantities of hydrocarbons are not discovered with an exploratory well, the costs of drilling the well are expensed.

The capitalized costs of our crude oil, natural gas, and NGL properties, on a depletion pool basis, cannot exceed the estimated undiscounted future net cash flows of that depletion pool. If net capitalized costs exceed undiscounted future net revenues, we generally must write down the costs of each depletion pool to the estimated discounted future net cash flows of that depletion pool. Unproved properties are evaluated at the lower of cost or fair market value. We incurred an impairment of proved property and impairment of unproved properties totaling $219.0 million and $7.4 million, respectively, during 2011, $6.1 million and $2.0 million, respectively, during 2010, and $174.8 million and $45.4 million, respectively, during 2009. Significant further declines in crude oil, natural gas, or NGL prices in the future or unsuccessful exploration efforts could cause further impairment write-downs of capitalized costs.

We review the carrying value of our properties for indicators of impairment on a quarterly basis using the prices in effect as of the end of each quarter. Once incurred, a write-down of oil and natural gas properties cannot be reversed at a later date, even if crude oil, natural gas, or NGL prices increase.

Lower crude oil, natural gas, or NGL prices could limit our ability to borrow under our credit facility.

Our credit facility has a current commitment amount of $1.0 billion, subject to a borrowing base that the lenders periodically redetermine based largely on the bank group’s assessment of the value of our crude oil, natural gas, and NGL properties, which in turn is impacted by crude oil, natural gas, and NGL prices. The current borrowing base under our credit facility is $1.3 billion. Declines in crude oil, natural gas, or NGL prices in the future could limit our borrowing base and reduce our ability to borrow under our credit facility. Additionally, divestitures of properties could result in a reduction of our borrowing base.

Our amount of debt may limit our ability to obtain financing for acquisitions, make us more vulnerable to adverse economic conditions, and make it more difficult for us to make payments on our debt.

As of December 31, 2011, we had $285.1 million, net of debt discount, of total long-term senior unsecured debt outstanding under our 3.50% Senior Convertible Notes Due 2027 ("3.50% Senior Convertible Notes"); $350.0 million of long-term senior unsecured debt outstanding relating to our 6.625% Senior Notes that we issued on February 7, 2011; $350.0 million of long-term senior unsecured debt outstanding relating to our 6.50% Senior Notes that we issued on November 8, 2011; and no outstanding borrowings under our secured credit facility (other than two outstanding letters of credit in the aggregate amount of $608,000, which reduce the amount available for borrowings under the facility on a dollar-for-dollar basis), resulting in $999.4 million of available debt capacity under our credit facility, assuming the borrowing conditions of this facility were met. Our long-term debt represented 40 percent of our total book capitalization as of December 31, 2011.

Our indebtedness could have important consequences for our operations, including:

- making it more difficult for us to obtain additional financing in the future for our operations and potential acquisitions, working capital requirements, capital expenditures, debt service, or other general corporate requirements;

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- requiring us to dedicate a substantial portion of our cash flows from operations to the repayment of our debt and the service of interest costs associated with our debt, rather than to productive investments;
- limiting our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making acquisitions, and paying dividends;
- placing us at a competitive disadvantage compared to our competitors that have less debt; and
- making us more vulnerable in the event of adverse economic or industry conditions or a downturn in our business.

Our ability to make payments on our debt and to refinance our debt and fund planned capital expenditures will depend on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory, and other factors that are beyond our control. If our business does not generate sufficient cash flow from operations or future sufficient borrowings are not available to us under our credit facility or from other sources, we might not be able to service our debt or fund our other liquidity needs. If we are unable to service our debt, due to inadequate liquidity or otherwise, we may have to delay or cancel acquisitions, defer capital expenditures, sell equity securities, divest assets, or restructure or refinance our debt. We might not be able to sell our equity securities, sell our assets, or restructure or refinance our debt on a timely basis or on satisfactory terms or at all. In addition, the terms of our existing or future debt agreements, including our existing and future credit agreements, may prohibit us from pursuing any of these alternatives. Further, changes in the credit ratings of our debt may negatively affect the cost, terms, conditions, and availability of future financing. The indenture under our 3.50% Senior Convertible Notes provides that under certain circumstances we have the option to settle our obligations under these senior convertible notes through the issuance of shares of our common stock if we so elect.

Our debt agreements, including the agreement governing our credit facility and the indentures governing the 6.625% Senior Notes and 6.50% Senior Notes, permit us to incur additional debt in the future, subject to compliance with restrictive covenants under those agreements. In addition, entities we may acquire in the future could have significant amounts of debt outstanding that we could be required to assume, and in some cases accelerate repayment thereof, in connection with the acquisition, or we may incur our own significant indebtedness to consummate an acquisition.

As discussed above, our credit facility is subject to periodic borrowing base redeterminations. We could be forced to repay a portion of our bank borrowings in the event of a downward redetermination of our borrowing base, and we may not have sufficient funds to make such repayment at that time. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowing base or arrange new financing, we may be forced to sell significant assets.

The agreements governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

Our debt agreements contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interests. Our ability to borrow under our credit facility is subject to compliance with certain financial covenants, including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest, taxes, depreciation, amortization, and exploration expense of no greater than 4.0 to 1.0, and (ii) maintenance of a current ratio of no less than 1.0 to 1.0, each as defined in our credit facility. Our credit facility also requires us to comply with certain financial covenants, including requirements that we maintain certain levels of stockholders' equity and limit our annual cash dividends to no more than $50.0 million. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

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The respective indentures governing the 6.625% Senior Notes and the 6.50% Senior Notes also contain covenants that, among other things, limit our ability and the ability of our subsidiaries to:

- incur additional debt;
- make certain dividends or pay dividends or distributions on our capital stock or purchase, redeem, or retire capital stock;
- sell assets, including capital stock of our subsidiaries;
- restrict dividends or other payments of our subsidiaries;
- create liens that secure debt;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all or a portion of our indebtedness. We do not have sufficient working capital to satisfy our debt obligations in the event of an acceleration of all or a significant portion of our outstanding indebtedness.

We are subject to operating and environmental risks and hazards that could result in substantial losses.

Crude oil and natural gas operations are subject to many risks, including human error and accidents that could cause personal injury, death and property damage, well blowouts, craterings, explosions, uncontrollable flows of crude oil, natural gas and associated liquids or well fluids, fires, adverse weather such as hurricanes in the South Texas & Gulf Coast region, freezing conditions in the Williston Basin of our Rocky Mountain region, floods, droughts, formations with abnormal pressures, pipeline ruptures or spills, pollution, releases of toxic gas such as hydrogen sulfide, and other environmental risks and hazards. If any of these types of events occurs, we could sustain substantial losses.

There is inherent risk of incurring significant environmental costs and liabilities in our operations due to our current and past generation, handling and disposal of materials, including solid and hazardous wastes and petroleum hydrocarbons. We may incur joint and several, strict liability under applicable United States federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from our leased or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under our control. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance, and could be subject to liabilities in the event of non-compliance. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the CERCLA or the Superfund law, the RCRA, the Clean Water Act, the CAA, the OPA, and analogous state laws. Under any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damage allegedly caused by the release of petroleum hydrocarbons or other wastes into the environment. As a result, we may incur substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development, or acquisitions, or cause us to incur losses.

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We maintain insurance against some, but not all, of these potential risks and losses. We have significant but limited coverage for sudden environmental damage. We do not believe that insurance coverage for the full potential liability that could be caused by sudden environmental damage or insurance coverage for environmental damage that occurs over time is available at a reasonable cost. In addition, pollution and environmental risks generally are not fully insurable. Further, we may elect not to obtain other insurance coverage under circumstances where we believe that the cost of available insurance is excessive relative to the risks to which we are subject. Accordingly, we may be subject to liability or may lose substantial assets in the event of environmental or other damages. If a significant accident or other event occurs and is not fully covered by insurance, we could suffer a material loss.

Following the severe Atlantic hurricanes in 2004, 2005, and 2008, the insurance markets suffered significant losses. As a result, insurance coverage for wind storms has become substantially more expensive, and future availability and costs of coverage are uncertain.

Our operations are subject to complex laws and regulations, including environmental regulations that result in substantial costs and other risks.

Federal, state, tribal, and local authorities extensively regulate the oil and natural gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may become more stringent and, as a result, may affect, among other things, the pricing or marketing of crude oil, natural gas and NGL production. Noncompliance with statutes and regulations and more vigorous enforcement of such statutes and regulations by regulatory agencies may lead to substantial administrative, civil, and criminal penalties, including the assessment of natural resource damages, the imposition of significant investigatory and remedial obligations and may also result in the suspension or termination of our operations. The overall regulatory burden on the industry increases the cost to place, design, drill, complete, install, operate, and abandon wells and related facilities and, in turn, decreases profitability.

Governmental authorities regulate various aspects of drilling for and the production of crude oil, natural gas, and NGLs, including the permit and bonding requirements of drilling wells, the spacing of wells, the unitization or pooling of interests in crude oil and natural gas properties, rights-of-way and easements, environmental matters, occupational health and safety, the sharing of markets, production limitations, plugging, abandonment, and restoration standards, oil and gas operations, and restoration. Public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain projects. Under certain circumstances, regulatory authorities may deny a proposed permit or right-of-way grant or impose conditions of approval to mitigate potential environmental impacts, which could, in either case, negatively affect our ability to explore or develop certain properties. Federal authorities also may require any of our ongoing or planned operations on federal leases to be delayed, suspended, or terminated. Any such delay, suspension, or termination could have a materially adverse effect on our operations.

Our operations are also subject to complex and constantly changing environmental laws and regulations adopted by federal, state, tribal and local governmental authorities in jurisdictions where we are engaged in exploration or production operations. New laws or regulations, or changes to current requirements, could result in material costs or claims with respect to properties we own or have owned. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. Under existing or future environmental laws and regulations, we could incur significant liability, including joint and several, strict liability under federal, state, and tribal environmental laws for noise emissions and for discharges of crude oil, natural gas, and associated liquids or other pollutants into the air, soil, surface water, or groundwater. We could be required to spend substantial amounts on investigations, litigation, and remediation for these discharges and other compliance issues. Any unpermitted release of petroleum or other pollutants from our operations could result not only in cleanup costs, but also natural resources, real or personal property and other compensatory damages and civil and criminal liability. Existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced, or altered in the future, may have a materially adverse effect on us.

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Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Operations in certain of our regions, such as our Rocky Mountain and Permian regions, are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Wildlife seasonal restrictions may limit access to federal leases or across federal lands. Possible restrictions may include seasonal restrictions in greater sage-grouse habitat during breeding and nesting seasons, within a certain distance of active raptor nests during fledging, and in big game winter or parturition ranges during winter or calving seasons. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Proposed federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of oil, natural gas and associated liquids from dense subsurface rock formations. We routinely apply hydraulic fracturing techniques to many of our oil and natural gas properties, including our unconventional resource plays in the Granite Wash of Texas and Oklahoma, the Eagle Ford shale of south Texas, and the Bakken/Three Forks formations in North Dakota. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow the flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving the use of diesel in the fluid system under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit or disclosure requirements or operational restrictions and also to associated permitting delays, litigation risk, and potential cost increases.

Certain states that we operate in, including Pennsylvania, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas ("RCT") and the public of certain information regarding the components and volume of water used in the hydraulic fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling and/or completion of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating a review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. 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. In addition, the United States Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the United States

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Department of the Interior is developing disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Additionally, certain members of Congress have called upon the United States Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the United States Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the United States Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their course and outcomes, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory processes.
Further, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion ("REC") techniques developed in EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology ("MACT") standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected by March or April, 2012.
Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing such activity to pursue legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect human health or the environment, including groundwater. Additional legislation or regulation could also lead to operational delays or increased costs in the exploration for and production of oil, natural gas, and associated liquids, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of additional federal, state, or local laws, or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and delays, which could adversely affect our financial position, results of operations, and cash flows.
On October 20, 2011, the EPA announced a schedule for development of standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works ("POTWs"). The regulations will be developed under the EPA's Effluent Guidelines Program under the authority of the Clean Water Act. The EPA anticipates issuing the proposed rules in 2014.
Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.
The hydraulic fracturing process on which we depend to drill for commercial quantities of crude oil, natural gas, and associated liquids requires the use and disposal of significant quantities of water.
Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or

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disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of natural gas.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

Certain United States federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

On September 12, 2011, President Obama sent to Congress a legislative package that included proposed legislation that, if enacted into law, would eliminate certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, among other proposals:

- the repeal of the percentage depletion allowance for oil and natural gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for certain domestic production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. It is unclear whether these or similar changes will be enacted. The passage of this legislation or any similar changes in 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. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Legislative and regulatory initiatives related to global warming and climate change could have an adverse effect on our operations and the demand for crude oil, natural gas, and NGLs.

In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing a comprehensive suite of regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. For example, the EPA has adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other regulates the permitting and emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. In the courts, several cases are pending that may increase the risk of claims being filed against companies that have significant greenhouse gas emissions. Such cases seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property. Any laws or regulations that restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken legal measures to reduce

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emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, gas, and NGLs we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition, and results of operations. Finally, it should be noted that some scientists have predicted that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If such effects were to occur, our operations could be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from flooding or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Current or proposed financial legislation and rulemaking could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Commodities Futures Trading Commission (the "CFTC") is required to implement rules relating to these activities by July 16, 2012. On October 18, 2011, the CFTC approved regulations to set position limits for certain futures and option contracts in the major energy markets, which regulations are presently being challenged in federal court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association. The Dodd-Frank Act may also require us to comply with margin requirements and with certain clearing and trade execution requirements in our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of 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 Dodd-Frank Act and 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. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Our ability to sell crude oil, natural gas and NGLs, and/or receive market prices for our production, may be adversely affected by constraints on gathering systems, processing facilities, pipelines and other transportation

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systems owned or operated by others or by other interruptions.
The marketability of our crude oil, natural gas, and NGL production depends in part on the availability, proximity, and capacity of gathering systems, processing facilities, and pipeline and other transportation systems owned or operated by third parties. The lack of available capacity in these systems and facilities can result in the shutting-in of producing wells, the delay or discontinuance of development plans for our properties, or lower price realizations. Although we have some contractual control over the processing and transportation of our production, material changes in these business relationships could materially affect our operations. Federal and state regulation of crude oil, natural gas, and NGLs production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines, infrastructure or capacity constraints, and general economic conditions could adversely affect our ability to produce, gather, process, and transport crude oil, natural gas, and NGLs.
In particular, if drilling in the Eagle Ford shale, Haynesville shale, Bakken/Three Forks resource play, and Granite Wash resource play continues to be successful, the amount of crude oil, natural gas, and NGLs being produced by us and others could exceed the capacity of, and result in strains on, the various gathering and transportation systems, pipelines, processing facilities, and other infrastructure available in these areas. It will be necessary for additional infrastructure, pipelines, gathering and transportation systems and processing facilities to be expanded, built or developed to accommodate anticipated production from these areas. Because of the current economic climate, certain processing, pipeline, and other gathering or transportation projects that might be, or are being, considered for these areas may not be developed timely or at all due to lack of financing or other constraints. In addition, capital and other constraints could limit our ability to build or access intrastate gathering and transportation systems necessary to transport our production to interstate pipelines or other points of sale or delivery. In such event, we might have to delay or discontinue development activities or shut in our wells to wait for sufficient infrastructure development or capacity expansion and/or sell production at significantly lower prices, which would adversely affect our results of operations and cash flows.
A portion of our 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, gathering, processing or transportation system access or capacity, 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 flows and results of operations.
New technologies may cause our current exploration and drilling methods to become obsolete.
The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.
Our business could be negatively impacted by security threats, including cybersecurity threats, terrorism, armed conflict, and other disruptions.
As a crude oil, natural gas, and NGL producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance

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that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.
Cybersecurity attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for crude oil, natural gas, and NGLs, all of which could adversely affect the markets for our operations. Energy assets might be specific targets of terrorist attacks. These developments have subjected our operations to increased risk and, depending on their occurrence and ultimate magnitude, could have a material adverse effect on our business.

Risks Related to Our Common Stock

The price of our common stock may fluctuate significantly, which may result in losses for investors.
From January 1, 2011, to February 16, 2012, the closing daily sale price of our common stock as reported by the New York Stock Exchange ranged from a low of $56.04 per share in January 2011 to a high of $86.85 per share in October 2011. We expect our stock to continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:
- changes in crude oil, natural gas, or NGL prices;
- variations in drilling, recompletion, and operating activity;
- changes in financial estimates by securities analysts;
- changes in market valuations of comparable companies;
- additions or departures of key personnel;
- future sales of our common stock; and
- changes in the national and global economic outlook.

We may not meet the expectations of our stockholders and/or of securities analysts at some time in the future, and our stock price could decline as a result.
Our certificate of incorporation and by-laws have provisions that discourage corporate takeovers and could prevent stockholders from receiving a takeover premium on their investment.
Our certificate of incorporation and by-laws contain provisions that may have the effect of delaying or preventing a change of control. These provisions, among other things, provide for non-cumulative voting in the election of members of the Board of Directors and impose procedural requirements on stockholders who wish to make nominations for the election of directors or propose other actions at stockholder meetings. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

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Shares eligible for future sale may cause the market price of our common stock to drop significantly, even if our business is doing well.

The potential for sales of substantial amounts of our common stock in the public market may have a materially adverse effect on our stock price. As of February 16, 2012, 64,068,540 shares of our common stock were freely tradable without substantial restriction or the requirement of future registration under the Securities Act of 1933. Also as of that date, options to purchase 458,263 shares of our common stock were outstanding, all of which were exercisable. These options are exercisable at prices ranging from $10.86 to $20.87 per share. In addition, restricted stock units (“RSUs”) providing for the issuance of up to a total of 308,412 shares of our common stock and 1,230,814 performance share units ("PSUs") were outstanding. PSUs are structurally the same as the previously granted Performance Share Awards or ("PSAs") (collectively known as "Performance Share Units" or "PSUs"). The PSUs represent the right to receive, upon settlement of the PSUs after the completion of a three-year performance period, a number of shares of our common stock that may be from zero to two times the number of PSUs granted, depending on the extent to which the underlying performance criteria have been achieved and the extent to which the PSUs have vested. In addition, we may issue additional shares of our common stock in connection with a put or conversion of our 3.50% Senior Convertible Notes. As of February 16, 2012, there were 64,114,366 shares of our common stock outstanding, which is net of 81,067 treasury shares.

We may not always pay dividends on our common stock.

Payment of future dividends remains at the discretion of the Board of Directors, and will continue to depend on our earnings, capital requirements, financial condition, and other factors. In addition, the payment of dividends is subject to a covenant in our credit facility limiting our annual cash dividends to no more than $50.0 million, and to covenants in the indentures for our 6.625% Senior Notes and 6.50% Senior Notes that limit our ability to pay dividends beyond a certain amount. Our Board of Directors may determine in the future to reduce the current semi-annual dividend rate of $0.05 per share, or discontinue the payment of dividends altogether.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the filing date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a materially adverse effect upon our financial condition, results of operations or cash flows.

We note that approximately 22,000 acres of our approximately 196,000 net acres in the Eagle Ford shale play in South Texas are the subject of a lawsuit captioned W.H. Sutton, et al. vs. St. Mary Land & Exploration Co., et al. instituted in the District Court of Webb County in and for the 49th Judicial District of Texas on May 13, 2010. The plaintiffs claim an aggregate overriding royalty interest of 7.46875% in production attributable to a 1966 oil, gas and mineral lease, and that such overriding royalty interest attaches to subsequent leases currently affecting the acreage that is the subject of the lawsuit, which had been released from the 1966 lease. At the original lease date, the 1966 lease was executed for approximately 40,000 acres. The plaintiffs seek to quiet title to their claimed overriding royalty interest and the recovery of unpaid overriding royalty interest proceeds allegedly due. We believe that the claimed overriding royalty interest has been terminated under the governing agreements and the applicable law, and have contested the plaintiffs' claims. Both parties filed motions for summary judgment, and on February 8, 2011, the District Court issued an order granting plaintiffs' motion for summary judgment and denying our motion for summary judgment. The order granting plaintiffs' motion for summary judgment did not award damages but reserved such determination for final order. We believe that the summary judgment is incorrect under the governing agreements and applicable law, and we have appealed the court's ruling. On September 30, 2011, the District Court entered final judgment for the plaintiffs and awarded damages of approximately $5.1 million, which includes prejudgment interest. The District Court also awarded attorneys fees and costs. We have appealed the District Court's judgment and obtained a stay pending appeal that prevents the plaintiffs from executing on the judgment.

We believe this lawsuit is entirely without merit and we will continue to vigorously contest this litigation. However, we cannot predict the ultimate outcome of this lawsuit. If the plaintiffs were to ultimately prevail, the overriding royalty interest would have the effect of reducing our net revenue interest in the affected acreage, which would negatively impact our economics in this portion of our acreage, but we do not believe would have a material adverse effect upon our financial condition, results of operations, or cash flows. For a more detailed discussion of our Eagle Ford shale play, see Core Operational Areas, South Texas & Gulf Coast Region in Part I, Items 1 and 2 of this report.

We recently filed, in Webb County, Texas, a declaratory judgment action, captioned SM Energy Company vs. W.H. Sutton, et al., seeking a judgment declaring that the 1966 lease terminated with respect to the remaining 18,000 acres, based upon a failure of continuous development, and that any overriding royalty interest claimed by the defendants' has been extinguished.

ITEM 4. MINE SAFETY DISCLOSURES

These disclosures are not applicable to us.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information. Our common stock is currently traded on the New York Stock Exchange under the ticker symbol “SM”. The following table presents the range of high and low intraday sales prices per share for the indicated quarterly periods in 2011 and 2010, as reported by the New York Stock Exchange:

Quarter Ended	High	Low
December 31, 2011	$ 88.50	$ 53.45
September 30, 2011	85.55	60.52
June 30, 2011	78.55	61.37
March 31, 2011	75.00	54.59
December 31, 2010	$ 59.82	$ 37.30
September 30, 2010	44.93	33.80
June 30, 2010	49.13	35.29
March 31, 2010	38.18	30.70

PERFORMANCE GRAPH

The following performance graph compares the cumulative return on our common stock, for the period beginning December 31, 2006, and ending on December 31, 2011, with the cumulative total returns of the Dow Jones U.S. Exploration and Production Board Index, and the Standard & Poor’s 500 Stock Index.

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN

The preceding information under the caption Performance Graph shall be deemed to be furnished, but not filed with the Securities and Exchange Commission.

Holders. As of February 16, 2012, the number of record holders of SM Energy's common stock was 90. Based upon inquiry, SM Energy had approximately 35,800 beneficial owners of its common stock in 2011.

Dividends. We have paid cash dividends to our stockholders every year since 1940. Annual dividends of $0.05 per share were paid in each of the years 1998 through 2004. Annual dividends of $0.10 per share were paid in 2005 through 2011. We expect that our practice of paying dividends on our common stock will continue,

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although the payment of future dividends will continue to depend on our earnings, cash flow, capital requirements, financial condition, and other factors, including the discretion of our Board of Directors. In addition, the payment of dividends is subject to covenants in our credit facility that limit our annual dividend payment to no more than $50.0 million per year. We are also subject to certain covenants under our 6.625% Senior Notes and 6.50% Senior Notes that restrict certain payments, including dividends; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. Based on our current performance, we do not anticipate that these covenants will restrict future annual dividend payments of $0.10 per share of common stock. Dividends are currently paid on a semi-annual basis. Dividends paid totaled $6.4 million in 2011 and $6.3 million in 2010.

Restricted Shares. We have no restricted shares outstanding as of December 31, 2011, aside from Rule 144 restrictions on shares held by insiders and shares issued to members of the Board of Directors under our Equity Incentive Compensation Plan (“Equity Plan”).

Purchases of Equity Securities by the Issuer and Affiliated Purchasers. The following table provides information about purchases by the Company and any affiliated purchaser (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the indicated quarters and year ended December 31, 2011, of shares of the Company’s common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

ISSUER PURCHASES OF EQUITY SECURITIES

	Total Number of Shares Purchased[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Program	Maximum Number of Shares that May Yet be Purchased Under the Program[(2)]
January 1, 2011 – March 31, 2011	8,878	$72.47	—	3,072,184
April 1, 2011 - June 30, 2011	—	$—	—	3,072,184
July 1, 2011 - September 30, 2011	123,504	$75.49	—	3,072,184
October 1, 2011 - October 31, 2011	—	$—	—	3,072,184
November 1, 2011 - November 30, 2011	88	$78.92	—	3,072,184
December 1, 2011 - December 31, 2011	—	$—	—	3,072,184
Total October 1, 2011 - December 31, 2011	88	$78.92	—	3,072,184
Total	132,470	$75.29	—	3,072,184

(1) All shares purchased in 2011 were to offset tax withholding obligations that occur upon the delivery of outstanding shares underlying RSUs and PSUs delivered under the terms of grants under the Equity Plan.

(2) In July 2006, our Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, we may repurchase up to 3,072,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility, the indentures governing our 6.625% Senior Notes and 6.50% Senior Notes and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, or borrowings under our credit facility. The stock repurchase program may be suspended or discontinued at any time. Please refer to Dividends above for a description of our dividend limitations.

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected supplemental financial and operating data for us as of the dates and periods indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II, Item 7 of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this report.

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(in millions, except per share data)				
Total operating revenues	$1,603.3	$1,092.8	$832.2	$1,301.3	$990.1
Net income (loss)	$215.4	$196.8	$(99.4)	$87.3	$187.1
Net income (loss) per share:					
Basic	$3.38	$3.13	$(1.59)	$1.40	$3.02
Diluted	$3.19	$3.04	$(1.59)	$1.38	$2.90
Total assets at year-end	$3,799.0	$2,744.3	$2,360.9	$2,697.2	$2,572.9
Long-term debt:					
Line of credit	$—	$48.0	$188.0	$300.0	$285.0
3.50% Senior Convertible Notes, net of debt discount	$285.1	$275.7	$266.9	$258.7	$251.1
6.625% Senior Notes	$350.0	$—	$—	$—	$—
6.50% Senior Notes	$350.0	$—	$—	$—	$—
Cash dividends declared and paid per common share	$0.10	$0.10	$0.10	$0.10	$0.10

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Supplemental Selected Financial and Operations Data

	Years Ended December 31,				
	2011	2010	2009	2008	2007
Balance Sheet Data (in millions)					
Total working capital (deficit)	$(42.6)	$(227.4)	$(87.6)	$15.2	$(92.6)
Total stockholders' equity	$1,462.9	$1,218.5	$973.6	$1,162.5	$902.6
Weighted-average common shares outstanding (in thousands)					
Basic	63,755	62,969	62,457	62,243	61,852
Diluted	67,564	64,689	62,457	63,133	64,850
Reserves					
Oil (MMBbl)	71.7	57.4	53.8	51.4	78.8
Gas (Bcf)	664.0	640.0	449.5	557.4	613.5
NGLs (MMBbl)	27.5	—	—	—	—
BCFE	1,259.2	984.5	772.2	865.5	1,086.5
Production and Operational (in millions)					
Oil, gas, and NGL production revenues	$1,332.4	$836.3	$616.0	$1,259.4	$912.1
Oil, gas, and NGL production expenses	$290.1	$195.1	$206.8	$271.4	$218.2
DD&A	$511.1	$336.1	$304.2	$314.3	$227.6
General and administrative	$118.5	$106.7	$76.0	$79.5	$60.1
Production Volumes					
Oil (MMBbl)	8.1	6.4	6.3	6.6	6.9
Gas (Bcf)	100.3	71.9	71.1	74.9	66.1
NGLs (MMBbl)	3.5	—	—	—	—
BCFE	169.7	110.0	109.1	114.6	107.5
Realized price					
Oil (per Bbl)	$88.23	$72.65	$54.40	$92.99	$67.56
Gas (per Mcf)	$4.32	$5.21	$3.82	$8.60	$6.74
NGL (per Bbl)	$53.32	$—	$—	$—	$—
Adjusted price (net of derivative cash settlements)					
Oil (per Bbl)	$78.89	$66.85	$56.74	$75.59	$62.60
Gas (per Mcf)	$4.80	$6.05	$5.59	$8.79	$7.63
NGL (per Bbl)	$47.90	$—	$—	$—	$—
Expense per MCFE					
LOE	$0.88	$1.10	$1.33	$1.46	$1.31
Transportation	$0.51	$0.19	$0.19	$0.19	$0.14
Production taxes	$0.32	$0.48	$0.37	$0.71	$0.58
DD&A	$3.01	$3.06	$2.79	$2.74	$2.12
General and administrative	$0.70	$0.97	$0.70	$0.69	$0.56
Statement of Cash Flow Data (in millions)					
Provided by operations	$760.5	$497.1	$436.1	$679.2	$632.1
(Used in) investing	$(1,264.9)	$(361.6)	$(304.1)	$(673.8)	$(805.1)
Provided by (used in) financing	$618.5	$(141.1)	$(127.5)	$(42.8)	$215.1

Note: Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to separately show natural gas and NGL production volumes, revenues, and pricing consistent with title transfer for each product. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices in Part II, Item 7 of this report.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion includes forward-looking statements. Please refer to Cautionary Information about Forward-Looking Statements in Part I, Items 1 and 2 of this report for important information about these types of statements.

Overview of the Company

General Overview

We are an independent energy company engaged in the acquisition, exploration, development, and production of oil, gas, and NGLs in onshore North America. Our assets include leading positions in the Eagle Ford shale and Bakken/Three Forks resource plays, as well as meaningful positions in the Granite Wash, Haynesville shale, and Woodford shale resource plays. We have built a portfolio of onshore properties in the contiguous United States primarily through early entrance into existing and emerging resource plays. This portfolio is comprised of properties with established production and reserves, prospective drilling opportunities, and unconventional resource prospects. We believe our strategy provides for stable and predictable production and reserve growth. Furthermore, by entering these plays early, we believe that we can capture larger resource potential at a lower cost.

In general, we generate almost all of our revenues and cash flows from the sale of produced oil, gas and NGLs. In 2011, we also generated meaningful gains and cash proceeds from the divestiture of oil and gas properties. Please refer to the discussion below under 2011 Highlights.

Our business strategy is focused on the early capture of resource plays in order to create and then enhance value for our shareholders, while maintaining a strong balance sheet. We strive to leverage industry leading exploration and leasehold acquisition teams to quickly acquire and test new resource play concepts at a reasonable cost. Once we have captured potential value through these efforts, our goal is to develop such potential through top tier operational and project execution, and as appropriate, mitigate our risk in asset development by divesting of all or a portion of certain assets. We continually examine our portfolio for opportunities to improve the quality of our asset base in order to maximize our returns and preserve our financial strength.

In 2011 we had the following financial and operational results:

- At year-end 2011, we had estimated proved reserves of 1,259.2 BCFE, of which 53 percent was natural gas and 67 percent was characterized as proved developed. We added 526.1 BCFE from our drilling program, the majority of which related to our activity in the Eagle Ford shale in South Texas, the Bakken/Three Forks plays in North Dakota, and the Haynesville Shale in East Texas. We sold 93.1 BCFE of proved reserves during the year related to assets located primarily in our South Texas & Gulf Coast region. We had negative price revisions that decreased our estimated proved reserves by 25.3 BCFE due to lower commodity prices in our gas-weighted regions. The prices used in the calculation of proved reserve estimates as of December 31, 2011, were $96.19 per Bbl, $4.12 per MMBtu, and $59.37 per Bbl, for oil, natural gas, and NGLs, respectively. These prices were 21 percent higher for oil and six percent lower for natural gas than the prices used at year-end 2010. Performance revisions in 2011 resulted in a net 36.8 BCFE increase in our estimate of proved reserves. This increase includes the impact of our conversion to three stream production, which is partially offset by negative engineering revisions due primarily to the failure of Woodford shale wells in our Mid-Continent region to satisfy our internal economic hurdles due to current commodity prices and well costs.
- The PV-10 value of our estimated proved reserves was $3.5 billion as of December 31, 2011, compared with $2.3 billion as of December 31, 2010. The after tax value, represented by the standardized measure calculation, was $2.6 billion as of December 31, 2011, compared with $1.7 billion as of

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December 31, 2010. The standardized measure calculation is presented in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown under Reserves in Part I, Items 1 and 2 of this report.

- We had record production in 2011. Our average daily production in 2011 was 274.8 MMcf of gas, 22.1 MBbl of oil, and 9.6 MBbl of NGLs, for an average equivalent production rate of 465.0 MMCFE, compared with 301.4 MMCFE in 2010, an increase of 54 percent year over year.
- We had record net income of $215.4 million and diluted earnings per share of $3.19 for the year ended December 31, 2011. This compares with net income of $196.8 million, or $3.04 per diluted share, for the year ended December 31, 2010.
- We had record cash flow from operating activities of $760.5 million for the year ended December 31, 2011, compared with $497.1 million as of December 31, 2010, which was an increase of 53 percent year over year.
- Costs incurred for oil and gas producing activities for the year ended December 31, 2011, were $1.6 billion, compared with $877.4 million for the same period in 2010.

Reserve Replacement, Finding and Development Costs, and Growth

Like all oil and gas exploration and production companies, we face the challenge of growing proved reserves. An exploration and production company depletes part of its asset base with each unit of oil, gas, or NGL it produces. Our future growth will depend on our ability to organically and economically add reserves in excess of production.

The following table provides various reserve replacement and finding and development cost metrics for the year ended December 31, 2011:

	Reserve Replacement Percentage				Finding and Development Cost per MCFE	
	Excluding Divestitures		Including Divestitures		Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	310	%	255	%	$2.85	$3.46
Drilling, including revisions	317	%	262	%	$2.79	$3.37
Drilling and acquisitions, excluding revisions	310	%	255	%	$2.85	$3.46
Drilling and acquisitions, including revisions	317	%	262	%	$2.79	$3.37
Reserve Acquisitions*	N/A*		N/A*		N/A*	N/A*
All-in	317	%	262	%	$2.89	$3.50

*There were no proved reserve acquisitions in 2011.

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The following table provides average reserve replacement and finding and development cost metrics for the three-year period ended December 31, 2011:

	Reserve Replacement Percentage		Finding and Development Cost per MCFE	
	Excluding Divestitures	Including Divestitures	Excluding Divestitures	Including Divestitures
Drilling, excluding revisions	262 %	205 %	$2.65	$3.39
Drilling, including revisions	259 %	201 %	$2.68	$3.45
Drilling and acquisitions, excluding revisions	262 %	205 %	$2.65	$3.39
Drilling and acquisitions, including revisions	259 %	201 %	$2.68	$3.45
Reserve Acquisitions	N/M*	N/M*	$3.36	N/M*
All-in	259 %	201 %	$2.83	$3.64

* N/M – Percentage or amount, as applicable, is not meaningful.

Our challenge is to grow net asset value per share, which we believe drives appreciation in our stock price over the long term. To accomplish this, we believe it is important to organically and economically replace annual production with new reserves. We believe annual reserve replacement percentage and finding and development costs are important analytical measures that are widely used by investors and industry peers in evaluating and comparing the performance of oil and gas companies. While single-year measurements have some meaning in terms of a trend, we believe that aberrations, causing both good and bad results, will occur over short intervals of time. The information used to calculate the above reserve replacement and finding and development cost metrics is included in the Supplemental Oil and Gas Information section located in Part II, Item 8 of this report. For additional information about these metrics, see the reserve replacement and finding and development cost terms in the Glossary of Oil and Gas Terms at the end of Part I, Items 1 and 2 of this report.

Oil, Gas, and NGL Prices

Our financial condition and the results of our operations are significantly affected by the prices we receive for oil, gas, and NGL production, which can fluctuate dramatically. Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. As a result, we reported realized prices for our natural gas production for periods through December 31, 2010, that were higher than industry benchmarks due to the price uplift associated with incremental value contained in the higher BTU content of our produced gas stream. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to show natural gas and NGL production volumes consistent with title transfer for each product. Projected rapid production growth from our NGL-rich assets associated with plant product sales contracts necessitated a change in our reporting of production volumes. Prior period production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the NGL volumes produced in prior periods. We sell the majority of our natural gas under contracts using first-of-the-month index pricing, which means gas produced in a given month is sold at the first-of-the-month price regardless of the spot price on the day the gas is produced. For assets where high BTU gas is sold at the wellhead, we also receive additional value for the high energy content contained in the gas stream. Our NGL production is generally sold using contracts paying us a monthly average of the posted OPIS Mont Belvieu daily settlement prices, adjusted for processing, transportation, and location differentials. Our crude oil and condensate are sold using contracts paying us either the average of the NYMEX WTI daily settlement price or the average of alternative posted prices for the periods in which the product is produced, adjusted for quality, transportation, and location differentials.

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The following table is a summary of commodity price data for the years ended December 31, 2011, 2010, and 2009.

	For the Years Ended December 31,		
	2011	2010	2009
Crude Oil (per Bbl):			
Average NYMEX price	$95.05	$79.51	$61.99
Realized price	$88.23	$72.65	$54.40
Natural Gas (per Mcf):			
Average NYMEX price	$4.00	$4.37	$3.94
Realized price	$4.32	$5.21	$3.82
NGLs (per Bbl):			
Average OPIS price	$59.47	$34.61	$46.92
Realized price	$53.32	N/A	N/A

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of NGL volumes in prior periods. Please refer to additional discussion above. Average OPIS prices per barrel of NGL, historical or strip, are based on a product mix of 37% Ethane, 6% Isobutane, 11% Normal Butane, 14% Natural Gasoline and 32% Propane for all periods presented.

We expect future prices for oil, gas, and NGLs to be volatile. In addition to supply and demand fundamentals, as a global commodity, the price of oil will likely continue to be impacted by real or perceived geopolitical risks in oil producing regions of the world, particularly in the Middle East. Additionally, the relative strength of the U.S. Dollar compared to other currencies could affect the price of oil. The supply of NGLs in the U.S. is expected to grow in the near term as a result of a number of industry participants targeting projects that produce these products, which could negatively impact future pricing. The pricing of several of the specific NGL products have strong correlations to the price of oil and accordingly are likely to directionally follow that market. Natural gas prices are under downward pressure due to current market oversupply because of high levels of drilling activity, a warmer than expected heating season, and slow economic growth. The 12-month strip prices for NYMEX WTI oil, NYMEX Henry Hub gas, and OPIS NGLs (same product mix as discussed above) as of December 31, 2011, were $98.85 per Bbl of oil, $3.30 per MMBtu of gas, and $55.78 per Bbl of NGLs, respectively. Comparable prices as of February 16, 2012, were $104.02 per Bbl, $3.11 per MMBtu, and $51.24 per Bbl, respectively.

While changes in quoted NYMEX oil and gas and OPIS NGL prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location, and transportation differentials for these products. Our realized prices shown in the table above do not include the impact of cash settlements from derivative contracts, which is consistent with all prior periods reported.

Derivative Activity

We use financial derivative instruments as part of our financial risk management program. We have a financial risk management policy governing our use of derivatives. The level of our production covered by derivatives is driven by the amount of debt on our balance sheet and the level of capital commitments and long-term obligations we have in place. With the derivative contracts we have in place, we believe we have established a base cash flow stream for our future operations and partially reduced our exposure to volatility in commodity prices. Our use of collars for a portion of the derivatives allows us to participate in some of the upward movements in oil, gas, and NGL prices while also setting a price floor for a portion of our production. Please see Note 10 – Derivative Financial Instruments of Part II, Item 8 of this report for additional information regarding our oil, gas, and NGL

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derivatives, and see the caption, Summary of Oil, Gas, and NGL Derivative Contracts in Place, later in this section. As of January 1, 2011, we elected to de-designate all commodity derivative contracts previously designated as cash flow hedges on December 31, 2010, and to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2011, changes in fair value of these contracts result in non-cash gains and losses that are recognized immediately in earnings. Realized cash settlements from our oil, gas, and NGL derivative contracts for the year ended December 31, 2011, resulted in a loss of $75.4 million, a gain of $48.0 million, and a loss $18.9 million, respectively.

The following table shows a reconciliation from our realized prices to our adjusted prices for the commodities indicated, including the effects of derivative cash settlements for 2011, 2010 and 2009:

	For the Year Ended December 31,		
	2011	2010	2009
Crude Oil (per Bbl):			
Realized price	$88.23	$72.65	$54.40
Plus (less) the effects of derivative cash settlements	(9.34)	(5.80)	2.34
Adjusted price, including the effects of derivative cash settlements	$78.89	$66.85	$56.74
Natural Gas (per Mcf):			
Realized price	$4.32	$5.21	$3.82
Plus the effects of derivative cash settlements	0.48	0.84	1.77
Adjusted price, including the effects of derivative cash settlements	$4.80	$6.05	$5.59
Natural Gas Liquids (per Bbl):			
Realized price	$53.32	$—	$—
(Less) the effects of derivative cash settlements	(5.42)	—	—
Adjusted price, including the effects of derivative cash settlements	$47.90	$—	$—

Note: Prior year NGL production volumes, revenues, and prices have not been reclassified to conform to the current presentation given the immateriality of the volumes in prior periods. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices above.

The Dodd-Frank Act included provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The Dodd-Frank Act requires the CFTC, the SEC, and other regulators to establish rules and regulations to implement the new legislation by July 16, 2012. The CFTC has proposed new rules governing margin requirements for uncleared swaps entered into by non-bank swap entities, and U.S. banking regulators have proposed new rules regarding margin requirements for uncleared swaps entered into by bank swap entities. The ultimate effect on our business of the proposed new rules and any additional regulations is currently uncertain. Of particular concern to us is whether the provisions of the final rules and regulations will allow us to qualify as a non-financial, commercial end user exempt from the requirements to post margin in connection with commodity price risk management activities. Final rules and regulations on major provisions of the legislation, such as new margin requirements, are to be established through regulatory rulemaking. Although we cannot predict the ultimate outcome of these rulemakings, new rules and regulations in this area may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil, gas, and NGL commodity prices.

2011 Highlights

Operational Activities. We operated eleven to twelve drilling rigs company-wide for most of 2011. We focused our operated drilling activity in 2011 on oil and NGL-rich gas programs and pursued certain other natural

gas projects of strategic importance to us. We also participated in higher levels of non-operated activity in oil and NGL-rich plays.

In our Eagle Ford shale program in South Texas, we operated two rigs at the beginning of the year and increased to five drilling rigs by year-end 2011. We focused our drilling in areas with higher BTU gas content and condensate yields. During 2011, we entered into arrangements to secure the pipeline takeaway capacity, drilling, and completion services required to accelerate and maintain our operated program. We continue to explore other arrangements to facilitate the growth of this program. Please refer to Note 6 – Commitments and Contingencies under Part II, Item 8 of this report and Delivery Commitments and Core Operational Areas under Part I, Items 1 and 2 of this report for additional discussion concerning these agreements. On our non-operated Eagle Ford acreage, the operator increased activity on our shared acreage throughout 2011. At year-end, ten drilling rigs were running in our non-operated Eagle Ford shale program this program. We participated with our partners in the construction of necessary infrastructure to support the growth in production associated with these assets during 2011.

We operated an average of three drilling rigs in the Williston Basin throughout 2011, all of which were focused on Bakken/Three Forks drilling. Our drilling results in these prospects met or exceeded our expectations. Elsewhere in the Rocky Mountain region, we tested the Niobrara formation in both southeastern and central Wyoming.

In our Mid-Continent region, we operated two drilling rigs in our Granite Wash program in western Oklahoma and the Texas Panhandle to test and delineate our acreage in the play. The majority of our acreage position is held by production, and we believe the potential from this emerging program could be significant.

In our ArkLaTex region, we had one operated rig in our Haynesville shale program at year-end, with a focus on holding the highest potential acreage through production.

Our Permian region operated one rig throughout 2011, splitting its efforts between the testing of Wolfberry down spacing and drilling Mississippian limestone targets as part of our exploration effort.

Production Results. The table below provides a regional breakdown of our 2011 production:

	ArkLaTex	Mid-Continent	South Texas & Gulf Coast	Permian	Rocky Mountain	Total(1)
Production:						
Oil (MMBbl)	0.1	0.4	2.6	1.3	3.7	8.1
Gas (Bcf)	29.3	28.6	34.7	3.5	4.2	100.3
NGLs (MMBbl)	0.1	0.1	3.2	—	—	3.5
Equivalent (BCFE)	30.1	31.6	69.7	11.5	26.7	169.7
Avg. Daily Equivalents (MMCFE/d)	82.5	86.7	191.1	31.5	73.3	465.0
Relative percentage	18 %	19 %	41 %	6 %	16 %	100 %

(1) Totals may not sum due to rounding.

In 2011, our production growth was led by our Eagle Ford shale program. Both our operated and non-operated programs targeting the Eagle Ford shale contributed more production than originally budgeted. Please refer to Comparison of Financial Results and Trends between 2011 and 2010 below for additional discussion on production.

Costs Incurred in Oil and Gas Producing Activities. Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

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	For the Year Ended December 31, 2011 (in millions)
Development costs	$1,208.3
Facility costs	112.4
Exploration costs	177.4
Acquisitions	
Leasing activity	55.2
Total, including asset retirement obligation	$1,553.3

Our operations are generally funded first using cash flows from operating activities. We also use borrowings under our credit facility. In 2011, we used proceeds from debt offerings and divestitures to help fund our capital investment activities. These sources allowed us to invest $1.5 billion for development and exploration, including facility costs, and $55.2 million for leasehold acquisitions. Total costs incurred during 2011 increased 77 percent from the prior year, reflecting our increased level of drilling activity, particularly in the Eagle Ford shale. Please refer to Overview of Liquidity and Capital Resources below for additional discussion on how we fund our capital program.

Acquisition and Development Agreement. We entered into an Acquisition and Development Agreement that provided for a transfer of a 12.5 percent working interest to Mitsui in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick, and Webb Counties, Texas. As consideration for the interests, Mitsui agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to our remaining interests in these assets until Mitsui has expended an aggregate $680.0 million on our behalf. Based on our forecast of the operator's current drilling plans, we estimate it will take three to four years to fully utilize the $680.0 million that Mitsui is obligated to carry. The agreement also provided for the conveyance of one-half of our ownership in related gathering assets in exchange for reimbursement by Mitsui of 50 percent of the total costs we paid for those assets through the closing date. The effective date of the transfer was March 1, 2011, and the transaction closed on December 2, 2011. Mitsui has reimbursed us for capital expenditures and other costs, net of revenues, that we paid and were attributable to the transferred interests during the period between the effective date and the closing date. We are applying these reimbursed funds to the 10 percent of our drilling and completion costs for the affected acreage not already covered by Mitsui's 90 percent carry.

Divestiture Activity. We had the following divestiture activity during 2011:

- Eagle Ford Shale Divestiture. In August 2011, we completed the divestiture of certain operated Eagle Ford shale assets located in our South Texas & Gulf Coast region, comprised of our entire operated acreage position in LaSalle County, Texas, as well as an immaterial adjacent block of our operated acreage in Dimmit County, Texas. Total divestiture proceeds were $230.8 million. The estimated gain on this divestiture was $194.6 million and post-closing adjustments, if any, are expected to be finalized in the first quarter of 2012.
- Mid-Continent Divestiture. In June 2011, we completed the divestiture of certain non-strategic assets located in our Mid-Continent region. Total divestiture proceeds were $35.8 million. The estimated gain on this divestiture was $28.5 million and post-closing adjustments, if any, are expected to be finalized in the first quarter of 2012.
- Rocky Mountain Divestiture. In January 2011, we completed the divestiture of certain non-strategic assets located in our Rocky Mountain region. Total divestiture proceeds were $45.5 million. The final gain on this divestiture was $27.2 million.
- Marcellus Divestiture Update. In July 2011, we entered into agreements with Endeavour International Corporation ("Endeavour") to divest of our Marcellus shale assets and related pipeline

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facilities located in Pennsylvania for $80.0 million net to our interest. Subsequently, Endeavour failed to consummate the transaction after giving notice of its intent to terminate the agreement. We have disputed Endeavour's right to take these actions, and are currently pursuing our legal remedies, including specific performance or damages from Endeavour. Due to the uncertainty surrounding the transaction, it was determined that these assets do not continue to meet the specific criteria required for presentation as assets held for sale. As a result, we have reclassified these assets previously classified as held for sale to assets held and used. We measured the assets at the lower of the assets' carrying amount before the assets were classified as held for sale, adjusted for any depreciation and depletion expense that would have been recognized had the assets been continuously classified as held and used, or the assets' fair value at the subsequent date that the assets no longer met the criteria for assets held for sale. As a result of this measurement, we recognized $14.7 million of DD&A expense and a $27.5 million write-down to proved and unproved oil and gas properties. This write-down is included in gain on divestiture activity in the accompanying consolidated statements of operations.

Outlook for 2012

We enter 2012 with a capital program expected to be in the range of $1.4 billion to $1.5 billion, of which approximately $1.2 billion to $1.3 billion will be focused on drilling and completion activities. Approximately 90 percent of our drilling budget will be spent on our operated projects, with approximately 70 percent of our 2012 drilling and completion capital being deployed in our operated Eagle Ford shale and Bakken/Three Forks programs.

In 2012, we plan to invest between $650 million and $700 million of drilling and completion capital in our operated Eagle Ford shale play. We began 2012 operating five rigs on our Eagle Ford shale acreage with plans to operate five to six drilling rigs in the first half of the year as we transition a larger proportion of our program to pad drilling. Once we have transitioned to pad drilling, we anticipate reducing activity by one rig in the second half to exit the year with five operated rigs, three of which will be focused on pad drilling. During 2011, we entered into an additional services agreement for gas takeaway capacity in 2013 and beyond in our operated Eagle Ford program, thereby increasing our number of providers to three and mitigating some risks of marketing our gas. During 2012, we plan to continue testing down spacing opportunities to determine the ultimate development spacing of our Galvan Ranch, Briscoe Ranch, and Apache Ranch areas. Along with down spacing tests, we will continue to refine our development program and well designs to optimize well performance and capital efficiency.

In our non-operated Eagle Ford shale program, the operator is currently operating ten drilling rigs and based on the operator's stated plans, our expectation is that the number of rigs will remain constant throughout the year. Mitsui will carry the majority of our non-operated drilling activity through 2012 and, as such, we expect to deploy minimal capital related to drilling in this program. Costs associated with items such as infrastructure are not carried by Mitsui, and we would be responsible for our proportionate share of the costs.

We plan to deploy between $160 million and $185 million of our capital budget in our operated Bakken/Three Forks program in the Williston Basin in 2012. We currently are operating three drilling rigs in this program and plan to add a fourth rig in the first half of 2012. Our plan with these rigs is to hold our Raven and Gooseneck prospects through production, and to begin infill drilling in our Bear Den prospect which is already held by production.

We also have activity planned in our Permian region, and Granite Wash, Niobrara, and Haynesville shale programs in 2012. Between $60 million and $70 million of our capital budget in 2012 is dedicated to our operated Granite Wash program, where we anticipate operating a three rig program throughout the year targeting NGL-rich washes. The remainder of our other operated program will be split between assets in the Permian basin and targets in the DJ basin and Powder River Basin. In the Haynesville shale, we have reduced the number of wells we plan to drill in 2012 in light of current natural gas prices. We now expect to invest approximately $35 million to $40 million during the year, after which time we will cease drilling activity in this area.

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Please refer to Overview of Liquidity and Capital Resources for additional discussion regarding how we intend to fund our 2012 capital program.

Financial Results of Operations and Additional Comparative Data

The table below provides information regarding selected production and financial information for the quarter ended December 31, 2011, and the immediately preceding three quarters. Additional details of per MCFE costs are contained later in this section.

	For the Three Months Ended			
	December 31, 2011	September 30, 2011	June 30, 2011	March 31, 2011
	(in millions, except for production data)			
Production (BCFE)	51.3	42.5	39.8	36.1
Oil, gas, and NGL production revenue	$397.0	$325.2	$333.9	$276.3
Realized hedge loss	$(6.2)	$(6.8)	$(6.3)	$(1.4)
Gain (loss) on divestiture activity	$(25.0)	$190.7	$30.0	$24.9
Lease operating expense	$43.5	$40.0	$33.2	$33.1
Transportation costs	$30.7	$23.9	$16.9	$15.0
Production taxes	$19.0	$13.8	$3.3	$17.8
DD&A	$167.3	$123.1	$115.4	$105.4
Exploration	$20.0	$11.3	$9.6	$12.7
Impairment of proved properties	$170.5	$48.5	$—	$—
General and administrative	$35.6	$29.8	$27.3	$25.9
Change in Net Profits Plan liability	$(0.8)	$(24.9)	$(14.0)	$14.2
Unrealized and realized derivative (gain) loss	$46.8	$(128.4)	$(43.9)	$88.4
Net income (loss)	$(120.7)	$230.1	$124.5	$(18.5)

Note: Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas to show natural gas and NGL production volumes, revenues, and pricing consistent with title transfer for each product. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices.

Selected Performance Metrics:

	For the Three Months Ended			
	December 31, 2011	September 30, 2011	June 30, 2011	March 31, 2011
Average net daily production equivalent (MMCFE per day)	557.9	462.1	436.9	401.4
Lease operating expense (per MCFE)	$(0.85)	$(0.94)	$(0.84)	$(0.92)
Transportation costs (per MCFE)	$(0.60)	$(0.56)	$(0.42)	$(0.41)
Production taxes as a percent of oil, gas, and NGL production revenue	4.8%	4.3%	1.0%	6.4%
Depletion, depreciation and amortization and asset retirement obligation liability accretion (per MCFE)	$(3.26)	$(2.89)	$(2.90)	$(2.92)
General and administrative (per MCFE)	$(0.69)	$(0.70)	$(0.69)	$(0.72)

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A year-to-year overview of selected production and financial information, including trends:

	As of and for the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2011	2010	2009	2011/2010	2010/2009	2011/2010	2010/2009
Net production volumes							
Oil (MMBbl)	8.1	6.4	6.3	1.7	0.1	27 %	— %
Natural gas (Bcf)	100.3	71.9	71.1	28.5	0.8	40 %	1 %
NGLs (MMBbl)	3.5	—	—	3.5	—	N/A	N/A
BCFE	169.7	110.0	109.1	59.7	0.9	54 %	1 %
Average net daily production							
Oil (MBbl per day)	22.1	17.4	17.3	4.7	0.1	27 %	— %
Natural gas (MMcf per day)	274.8	196.9	194.8	78.0	2.1	40 %	1 %
NGLs (MBbl per day)	9.6	—	—	9.6	0.0	N/A	N/A
Equivalent (MMCFE per day)	465.0	301.4	298.8	163.6	2.6	54 %	1 %
Oil, gas, & NGL production revenues (in millions)							
Oil production revenue	$712.8	$461.9	$344.3	$250.9	$117.6	54 %	34 %
Gas production revenue	433.4	374.4	271.7	59.0	102.7	16 %	38 %
NGL production revenue	186.2	—	—	186.2	—	N/A	N/A
Total	$1,332.4	$836.3	$616.0	$496.1	$220.3	59 %	36 %
Oil, gas, & NGL production expense (in millions)							
Lease operating expenses	$149.8	$121.5	$145.5	$28.3	$(24.0)	23 %	(16)%
Transportation costs	86.4	21.2	20.6	65.2	0.6	308 %	3 %
Production taxes	53.9	52.4	40.7	1.5	11.7	3 %	29 %
Total	$290.1	$195.1	$206.8	$95.0	$(11.7)	49 %	(6)%
Realized price							
Oil (per Bbl)	$88.23	$72.65	$54.40	$15.58	$18.25	21 %	34 %
Natural gas (per Mcf)	$4.32	$5.21	$3.82	$(0.89)	$1.39	(17)%	36 %
NGLs (per Bbl)	$53.32	$—	$—	$53.32	$—	N/A	N/A
Per MCFE data							
Realized price	$7.85	$7.60	$5.65	$0.25	$1.95	3 %	35 %
Lease operating expense	(0.88)	(1.10)	(1.33)	0.22	0.23	(20)%	(17)%
Transportation costs	(0.51)	(0.19)	(0.19)	(0.32)	—	168 %	— %
Production taxes	(0.32)	(0.48)	(0.37)	0.16	(0.11)	(33)%	30 %
General and administrative	(0.70)	(0.97)	(0.70)	0.27	(0.27)	(28)%	39 %
Operating profit, before the effects of derivative cash settlements	$5.44	$4.86	$3.06	$0.58	$1.80	12 %	59 %
Derivative cash settlements	(0.27)	0.22	1.29	(0.49)	(1.07)	(223)%	(83)%
Operating profit, including the effects of derivative cash settlements	$5.17	$5.08	$4.35	$0.09	$0.73	2 %	17 %
Depletion, depreciation and amortization and asset	$(3.01)	$(3.06)	$(2.79)	$0.05	$(0.27)	(2)%	10 %

retirement obligation liability
accretion

Note: Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to separately show natural gas and NGL production volumes, revenues, and pricing consistent with title transfer for each product. Please refer to additional

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discussion above under the caption Oil, Gas, and NGL Prices.
We present per MCFE information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe require analysis. Average daily production for the year ended December 31, 2011, increased 54 percent compared to the same period in 2010, driven mainly by the development of our Eagle Ford shale program.
Changes in production volumes, revenues, and costs reflect the cyclical and highly volatile nature of our industry. Our realized price for the year ended December 31, 2011, increased three percent from the same period in 2010 due to a higher realized price received for oil. Please refer to our discussion above under Oil, Gas, and NGL prices for information regarding how we have changed our reporting for natural gas volumes to show post processing production volumes of natural gas and NGLs for assets where our sales contracts permit us to do so.
Our LOE on a per MCFE basis for the year ended December 31, 2011, decreased 20 percent compared to the same period in 2010. The divestiture of non-strategic properties with meaningfully higher per unit operating costs within our Rocky Mountain and Mid-Continent regions in 2011 and Permian region in late 2010 is the driver of the decline in LOE from 2010. In addition, our LOE declined on a per MCFE basis due to higher production volumes. We believe the current high level of industry activity, particularly in plays with oil and rich-gas, has the potential to increase lease operating costs in 2012.

Production taxes on a per MCFE basis for the year ended December 31, 2011, decreased 33 percent compared to the same period in 2010. We generally expect production taxes to trend with oil, gas, and NGL revenues. We received notification in the second quarter of 2011 that wells within our Eagle Ford and Haynesville shale plays qualified for a severance tax incentive program in Texas. As a result, a sizable incentive tax rebate was recorded and our severance tax accruals were adjusted downward. We expect that substantially all future operated wells to be drilled in these areas will qualify for enacted reduced tax rates.

Transportation costs on a per MCFE basis for the year ended December 31, 2011, increased 168 percent compared to the same period in 2010. This is a result of increased production in our Eagle Ford shale program, where transportation arrangements have resulted in higher per unit transportation costs due to the lack of existing infrastructure in this emerging play. We anticipate transportation costs will continue to increase on a per MCFE basis as the Eagle Ford shale becomes a larger portion of our production.

Our general and administrative expense on a per MCFE basis for the year ended December 31, 2011, decreased 28 percent compared to the same period in 2010, because production increased at a faster rate than our general and administrative expense. A portion of our general and administrative expense is linked to our profitability and cash flow, which are driven in large part by the realized commodity prices we receive for our production. The Net Profits Plan and a portion of our short-term incentive compensation are tied to net revenues and therefore are subject to variability.

Our operating profit, including the effects of derivative cash settlements, for the year ended December 31, 2011, increased two percent, on a per MCFE basis, compared to the same period in 2010.
Our depletion, depreciation, and amortization, including asset retirement obligation accretion expense, for the year ended December 31, 2011, decreased two percent, on a per MCFE basis, compared to the same period in 2010. Overall the property balances between 2011 and 2010 remained relatively constant while the reserve base and production increased, causing the per unit depletion, depreciation and amortization rate ("DD&A rate") to decrease. Our DD&A rate can also fluctuate as a result of impairments, divestitures, and changes in the mix of our production and the underlying proved reserve volumes. Additionally, the accounting treatment for assets that are classified as assets held for sale can impact the DD&A rate since properties held for sale are not depleted.
Please refer to Comparison of Financial Results and Trends between 2011 and 2010 for additional discussion on oil, gas, and NGL production expense, DD&A, and general and administrative expense.

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Financial information (in millions, except shares and per share amounts):

	As of and for the Years Ended December 31,			Amount Change Between		Percent Change Between	
	2011	2010	2009	2011/ 2010	2010/ 2009	2011/ 2010	2010/ 2009
Working deficit	$(42.6)	$(227.4)	$(87.6)	$184.8	$(139.8)	(81)%	160 %
Long-term debt	$985.1	$323.7	$454.9	$661.4	$(131.2)	204 %	(29)%
Stockholders' equity	$1,462.9	$1,218.5	$973.6	$244.4	$244.9	20 %	25 %
Net income (loss)	$215.4	$196.8	$(99.4)	$18.6	$296.2	9 %	(298)%
Basic net income (loss) per common share	$3.38	$3.13	$(1.59)	$0.25	$4.72	8 %	(297)%
Diluted net income (loss) per common share	$3.19	$3.04	$(1.59)	$0.15	$4.63	5 %	(291)%
Basic weighted-average common shares outstanding (in thousands)	63,755	62,969	62,457	786	512	1 %	1 %
Diluted weighted-average common shares outstanding (in thousands)	67,564	64,689	62,457	2,875	2,232	4 %	4 %

Basic weighted-average common shares outstanding used in our December 31, 2011, 2010, and 2009, basic net income (loss) per common share calculations reflect increases in outstanding shares related to stock option exercises and vesting of RSUs. Our December 31, 2011, basic net income (loss) per common share calculation also includes common stock issued upon the settlement of PSUs. Diluted weighted-average common shares outstanding used in our December 31, 2011, and 2010, diluted net income per common share calculations include nonvested RSUs, contingent PSUs, and in-the-money stock options. Our December 31, 2011, diluted net income per common share calculation also includes the impact of our 3.50% Senior Convertible Notes. There were no dilutive shares included in our year-end 2009 diluted net income (loss) per common share calculation, as we recognized a net loss for the period.

In 2011, our average stock price exceeded the conversion price of $54.42 of our 3.50% Senior Convertible Notes, thus making them potentially dilutive for the first time. As of the filing date our stock price is trading above the $54.42 conversion price, therefore we expect our 3.50% Senior Convertible Notes to have a dilutive impact on our first quarter 2012 diluted net income per common share calculation. Please refer to Note 1 - Summary of Significant Accounting Policies and Note 7 - Compensation Plans in Part II, Item 8 of this report for detailed components of our net income (loss) per common share calculation.

Comparison of Financial Results and Trends between 2011 and 2010

Oil, gas, and NGL production revenue. Average daily production for the year ended December 31, 2011, increased 54 percent to 465.0 MMCFE, compared with 301.4 MMCFE for the same period in 2010. Please refer to the discussion above under Oil, Gas, and NGL Prices regarding how we have changed our reporting for natural gas and NGL volumes. The following table presents the regional changes in our production and oil, gas, and NGL revenues and costs between the two years:

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	Average Net Daily Production Added (Lost) (MMCFE/d)	Oil, Gas & NGL Revenue Added (Lost) (in millions)	Production Costs Increase (Decrease) (in millions)
ArkLaTex	43.2	$57.6	$5.2
Mid-Continent	(4.8)	5.7	(1.1)
South Texas & Gulf Coast	129.0	348.9	79.0
Permian	(8.7)	(12.2)	(0.3)
Rocky Mountain	4.9	96.1	12.2
Total	163.6	$496.1	$95.0

The largest regional production increase occurred in the South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program. Activity in our Eagle Ford shale program continues to increase, and we expect production from this region to increase for the next several years. We also saw an increase in production in our ArkLaTex region, as a result of strong production performance from wells drilled in our Haynesville shale program in late 2010 and early 2011.

The following table summarizes the realized prices we received in 2011 and 2010, before the effects of derivative cash settlements:

	For the Years Ended December 31, 2011	2010
Realized oil price ($/Bbl)	$88.23	$72.65
Realized gas price ($/Mcf)	$4.32	$5.21
Realized NGL price ($/Bbl)	$53.32	$—
Realized equivalent price ($/MCFE)	$7.85	$7.60

Note: Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head. Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to separately show natural gas and NGL production volumes, revenues, and pricing consistent with title transfer for each product. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices.

The three percent increase in realized equivalent price per MCFE coupled with a 54 percent increase in production volumes between periods resulted in a meaningful increase in revenue. We expect our realized price to trend with commodity prices. At current levels of anticipated activity, we expect production volumes to increase annually for the next several years.

Realized hedge (loss) gain. We recorded a net realized hedge loss of $20.7 million for the year ended December 31, 2011, compared with a net realized hedge gain of $23.5 million for the same period in 2010. The realized net loss in 2011 is comprised of realized cash settlements on commodity derivative contracts that were previously recorded in AOCL, whereas the realized net gain in 2010 is comprised of realized cash settlements on all commodity derivative contracts. Our realized oil, gas, and NGL hedge gains and losses are a function of commodity prices at the time of settlement and the price at the time the derivative transaction was entered into.

Gain on divestiture activity. We recorded a gain on divestiture activity of $220.7 million, which is net of the $27.5 million write-down related to our Marcellus assets, for the year ended December 31, 2011, compared with $155.3 million for the comparable period of 2010. The 2011 gain relates to the divestitures of oil and gas properties located in our South Texas & Gulf Coast, Rocky Mountain, and Mid-Continent regions. The 2010 gain was mainly related to the divestitures of non-strategic oil and gas properties located in our Rocky Mountain and Permian regions. We will continue to evaluate our portfolio to determine whether there are non-strategic properties we could divest. Please refer to Divestiture Activity under 2011 Highlights for additional discussion.

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Marketed gas system revenue and expense. Marketed gas system revenue was $69.9 million for the year ended December 31, 2011, compared with $70.1 million for the year ended December 31, 2010. Concurrent with the decrease in marketed gas system revenue, marketed gas system expense decreased to $64.2 million for the year ended December 31, 2011, from $66.7 million for the comparable period of 2010. We expect that marketed gas system revenue and expense will continue to trend with increases and decreases in production and our net realized price for natural gas.

Oil, gas, and NGL production expense. Total production costs increased $95.0 million or 49 percent, to $290.1 million for the year ended December 31, 2011, compared with $195.1 million in 2010. Total oil, gas, and NGL production costs per MCFE decreased $0.06 to $1.71 for the year ended December 31, 2011, compared with $1.77 in 2010. This decrease is comprised of the following:

- A $0.23 decrease in recurring LOE on a per MCFE basis reflects the sale of non-strategic properties in the Rocky Mountain and Mid-Continent regions in 2011 and the Permian region in late 2010 with higher per unit LOE costs that resulted in lower LOE on a per unit basis year over year. We expect that the various resources required to service our industry, particularly those located in basins with liquids-rich projects, will become more sought after and harder to secure as a result of an increase in activity targeting oil and NGL plays. Accordingly, we expect to see upward pressure on recurring LOE in 2012.
- A $0.16 decrease in production taxes on a per MCFE basis is due to severance tax incentives in Texas that benefit our assets in the South Texas & Gulf Coast and Mid-Continent regions. Please refer to our production tax discussion under the caption A year-to-year overview of selected production and financial information, including trends for additional information.
- A $0.01 increase in workover LOE on a per MCFE basis related primarily to increased workover activity in our South Texas & Gulf Coast region.
- A $0.32 increase in transportation costs on a per MCFE basis is primarily the result of increased production in our Eagle Ford shale program, which has higher per unit transportation costs than our Company average. Please refer to our caption A year-to-year overview of selected production and financial information, including trends for additional information.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased 52 percent to $511.1 million in 2011 compared with $336.1 million in 2010. DD&A expense per MCFE decreased two percent to $3.01 in 2011 compared to $3.06 in 2010. Please refer to the discussion under the caption A year-to -year overview of selected production and financial information, including trends for additional information.

Exploration. The components of exploration expense are summarized as follows:

	Years Ended December 31,	
	2011	2010
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$7.3	$21.5
Exploratory dry hole	0.3	0.3
Overhead and other expenses	45.9	42.1
Total	$53.5	$63.9

Exploration expense decreased 16 percent to $53.5 million in 2011 compared with $63.9 million for the same period in 2010. The majority of the change in exploration expense between 2011 and 2010 is due to a decreased amount spent on seismic as our current plays become more established. We continue to test our current resource plays and expect to maintain a modest exploratory program in future periods. Any exploratory well incapable of producing oil, gas, or NGLs in commercial quantities is deemed an exploratory dry hole, and impacts the amount of exploration expense we record. The amount of dry hole expense included in exploration expense

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during 2011 and 2010 was minimal. The decreased geological and geophysical costs were partially offset by an increase in exploration costs related to equity incentive compensation expense as discussed under General and administrative below.

Impairment of proved properties. We recorded a $219.0 million impairment of proved oil and gas properties in 2011 compared to $6.1 million in 2010. The impairment in 2011 was related to assets located in our ArkLaTex region, which were impacted by significantly lower natural gas prices in the second half of 2011. Proved property impairments are more likely to occur in periods of low commodity prices.

Abandonment and impairment of unproved properties. We recorded abandonment and impairment of unproved properties expense of $7.4 million for the year ended December 31, 2011, primarily associated with lease expirations in our ArkLaTex region. We recorded $2.0 million of abandonment and impairment of unproved properties expense for the comparable period in 2010, primarily associated with lease expirations in our Rocky Mountain and ArkLaTex regions. We expect abandonments and impairments of unproved properties to be more likely to occur in periods of low commodity prices, because low prices negatively impact operating cash flows available for exploration and development and also negatively impact anticipated economic performance.

General and administrative. General and administrative expense increased 11 percent, to $118.5 million for the year ended December 31, 2011, compared with $106.7 million for the same period in 2010. G&A decreased $0.27 to $0.70 per MCFE for the year ended December 31, 2011, compared to $0.97 per MCFE for the same period in 2010.

The total increase in general and administrative expense for the year ended December 31, 2011, includes $8.9 million relating to increases in base and equity incentive compensation and accruals for cash bonuses, as well as a $4.7 million increase in corporate office expenses. The increase in overall compensation and corporate office expenses is largely the result of an increase in employee headcount between the two periods. G&A expense decreased as a result of a $1.3 million increase in COPAS overhead reimbursements, caused by an increase in our operated well count resulting from our drilling efforts, and a $500,000 decrease in cash payments accrued under the Net Profits Plan. We expect payments made under the Net Profits Plan to trend with commodity prices.

Change in Net Profits Plan liability. Generally, this non-cash item is related to the change in the estimated value of the associated liability between the reporting periods. Please refer to Note 11 - Fair Value Measurements in Part II, Item 8 of this report for the impact the direct payment made to cash out several pools had on our change in Net Profits Plan liability. For 2011, the change in Net Profits plan liability, a non-cash item, was a $25.5 million benefit compared to a $34.4 million benefit in 2010. This non-cash charge or benefit is directly related to the change in the estimated value of the associated liability between the reporting periods. We broadly expect the change in our liability to continue to trend with changes in strip prices. The change in our liability is subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs. Payments made to participants as a result of divestitures will also impact our liability.

Unrealized and realized derivative (gain) loss. We recognized an unrealized and realized derivative gain of $37.1 million in 2011 compared to a loss of $8.9 million for the same period in 2010. The 2011 amount includes gains resulting from unrealized changes in fair value on commodity derivative contracts of $62.8 million and realized cash settlement losses on derivatives for which unrealized changes in fair value were not previously recorded in other comprehensive loss of $25.7 million. The 2010 balance is comprised solely of the ineffective portion of derivatives designated as cash flow hedges. Please refer to Note 10 - Derivative Financial Instruments in Part II, Item 8 of this report for additional discussion.

Other operating expense. Other expense was $17.6 million in 2011 compared with $3.0 million in 2010. The increase is a result of commission and legal costs associated with our Acquisition and Development Agreement with Mitsui, as well as legal costs related to the arbitration proceedings against Anadarko E&P Company, LP during the second half of 2011. Please refer to Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement, in Part II, Item 8 of this report for additional discussion on our Acquisition and Development

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Agreement.
Income tax (expense) benefit . Income tax expense totaled $123.6 million for 2011 compared with $118.1 million for 2010, resulting in effective tax rates of 36.5 percent and 37.5 percent, respectively. The effective rate change from 2010 primarily reflects changes in the mix of the highest marginal state tax rates, a multi-year research and experimentation credit claim, an adjustment for anticipated utilization of charitable contributions carryovers, and differing effects of other permanent differences including percentage depletion. Our current income tax benefit in 2011 is $204,000 compared with current income tax expense of $3.5 million in 2010. These amounts were three percent of the total income tax expense or benefit for 2010 and were not material for 2011.

At the end of 2010, federal legislation was passed making qualified property placed in service after September 8, 2010, and before January 1, 2012, eligible for 100 percent bonus depreciation. This same law made qualified property placed in service between January 1, 2010, and December 31, 2012, eligible for the 50 percent bonus depreciation election. We continue to be in an accelerated development mode on several unconventional projects. As a result, our election to utilize bonus depreciation for 2009, 2010, and 2011 is having the anticipated impact of reducing alternative minimum tax thereby, resulting in lower amounts of current income tax benefit/expense reported above. In 2011 we believe we will generate a net operating loss for income tax purposes and will carry a portion of that loss back to 2010 to recover most of the tax paid in that year. The remaining net operating loss is expected to be utilized in future years. We expect that the creation and utilization of net operating losses will limit our future ability to deduct charitable contribution carryovers from prior years so we recorded a valuation allowance related to that item.

During 2011, we completed a multi-year research and experimentation credit study. The study enabled us to establish credit claims for prior years and the current year. Tax law allowing the calculation of these credits has not been extended past December 31, 2011 as of the filing of this report. We expect to benefit from utilization of the remaining credits in future years. Please refer to Risk Factors - Risks Related to Our Business for additional discussion.

Comparison of Financial Results between 2010 and 2009
Oil and gas production revenue. Average daily production for the year ended December 31, 2010, increased one percent to 301.4 MMCFE, compared with 298.8 MMCFE for the same period in 2009. The following table presents the regional changes in our production and oil and gas revenues and costs between the two years.

	Average Net Daily Production Added (Lost) (MMCFE/d)	Oil and Gas Revenue Added (in millions)	Production Costs Increase (Decrease) (in millions)
ArkLaTex	(1.5)	$7.4	$(5.8)
Mid-Continent	(7.2)	23.9	4.0
South Texas & Gulf Coast	35.4	131.4	20.6
Permian	(1.3)	37.8	2.2
Rocky Mountain	(22.8)	19.8	(32.7)
Total	2.6	$220.3	$(11.7)

The largest regional production decrease occurred in the Rocky Mountain region as a result of our divestitures of non-strategic oil and gas assets that occurred in the fourth quarter of 2009 and first quarter of 2010. The largest production growth occurred in our South Texas & Gulf Coast region as a result of production from drilling activity in our Eagle Ford shale program.
The following table summarizes the average realized prices we received in 2010 and 2009, before the effects of hedging:

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	For the Years Ended December 31,	
	2010	2009
Realized oil price ($/Bbl)	$72.65	$54.40
Realized gas price ($/Mcf)	$5.21	$3.82
Realized equivalent price ($/MCFE)	$7.60	$5.65

The 35 percent increase in average realized prices per MCFE coupled with a one percent increase in production volumes between periods resulted in higher oil and gas revenue.

Realized hedge (loss) gain. We recorded a net realized hedge gain of $23.5 million for the year ended December 31, 2010, compared with a net realized hedge gain of $140.6 million for the same period in 2009. These gains were mainly related to favorable settlements on natural gas hedges. The realized net gains in 2010 and 2009 are comprised of realized cash settlements on all commodity derivative contracts.

Marketed gas system revenue and expense. Marketed gas system revenue increased $11.6 million to $70.1 million for the year ended December 31, 2010, compared with $58.5 million for the year ended December 31, 2009. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $9.1 million to $66.7 million for the year ended December 31, 2010, compared with $57.6 million for the comparable period of 2009.

Gain on divestiture activity. We recorded a gain on divestiture activity of $155.3 million for the year ended December 31, 2010, compared with $11.4 million for the comparable period of 2009. The 2010 gain relates to the divestitures of non-strategic oil and gas properties located in our Rocky Mountain and Permian regions. The 2009 gain was mainly related to the Hanging Woman Basin property divestiture that closed in late 2009.

Oil and gas production expense. Total production costs decreased $11.7 million or six percent to $195.1 million for the year ended December 31, 2010, compared with $206.8 million in 2009. Total oil and gas production costs per MCFE decreased $0.12 to $1.77 for the year ended December 31, 2010, compared with $1.89 in 2009. This decrease is comprised of the following:

- A $0.23 decrease in recurring LOE on a per MCFE basis reflects the sale of non-strategic properties in late 2009 and early 2010 with higher per unit LOE costs, which resulted in lower LOE on a per unit basis year over year.

- A $0.11 increase in production taxes on a per MCFE basis is due to the increase in realized prices between periods.

- Workover LOE and transportation costs on a per MCFE basis remained flat year over year.

Depletion, depreciation, amortization, and asset retirement obligation liability accretion. DD&A increased $31.9 million, or ten percent, to $336.1 million in 2010 compared with $304.2 million in 2009. DD&A expense per MCFE increased ten percent to $3.06 in 2010 compared to $2.79 in 2009. The increase was impacted by our divestiture of lower cost basis properties in 2010, and higher DD&A rates in our Eagle Ford and Haynesville programs.

Exploration. The components of exploration expense are summarized as follows:

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	Years Ended December 31,	
	2010	2009
Summary of Exploration Expense	(in millions)	
Geological and geophysical expenses	$21.5	$20.2
Exploratory dry hole	0.3	7.8
Overhead and other expenses	42.1	34.2
Total	$63.9	$62.2

Exploration expense increased $1.7 million, or three percent, to $63.9 million in 2010 compared with $62.2 million for the same period in 2009. The overall increase in expense primarily relates to an increase in exploration overhead, which is partially offset by a decrease in exploratory dry hole expense. In 2009, we had $7.8 million of exploratory dry hole expense related to properties in our ArkLaTex region compared with minimal exploratory dry hole expense in 2010. Other increases in exploration costs related to an increase in equity incentive compensation expense are discussed under General and administrative below.

Impairment of proved properties. We recorded a $6.1 million impairment of proved oil and gas properties in 2010 compared to $174.8 million in 2009. A significant decrease in commodity prices, including differentials, during the first quarter of 2009 caused the majority of the non-cash impairment in that year. The largest portion of the impairment in 2009 was $97.3 million related to assets located in the Mid-Continent region which were impacted at the end of the first quarter by low natural gas prices and wider than normal differentials.

Abandonment and impairment of unproved properties. During 2010, we abandoned or impaired $2.0 million of unproved properties compared with $45.4 million for 2009. The largest specific components of the 2009 impairment and abandonment related to our Floyd shale acreage located in Mississippi and certain acreage in Oklahoma. Additionally in 2009, we incurred write-offs related to acreage that we did not maintain or related to acreage that we did not believe will be prospective.

Impairment of materials inventory. There were no impairments of materials inventory recorded in 2010. We recorded a $14.2 million impairment of materials inventory for the year ended December 31, 2009. The 2009 inventory impairment was caused by a decrease in the value of tubular goods and other raw materials.

General and administrative. General and administrative expense increased $30.7 million, or 40 percent, to $106.7 million for the year ended December 31, 2010, compared with $76.0 million for the same period in 2009. G&A increased $0.27 to $0.97 per MCFE for the year ended December 31, 2010, compared to $0.70 per MCFE for the same period in 2009.

General and administrative expense increased due to a $21.9 million increase in base compensation, cash bonus, and long-term incentive compensation expense for the year ended December 31, 2010, compared with the same period in 2009. The increase in cash bonus and long-term incentive compensation expense reflects compensation expense associated with the PSAs granted in the third quarter of 2010, as well as the improvement in our performance and the anticipated achievement of various performance criteria, established by the Compensation Committee of our Board of Directors.

Additionally, G&A expense increased as a result of a $5.1 million decrease in COPAS overhead reimbursements, caused by a decrease in our operated well count resulting from our recent divestiture efforts, and a $1.4 million increase in cash payments accrued under the Net Profits Plan.

Bad debt recovery. We did not record any bad debt expense or recovery of bad debt expense in 2010. In 2008, SemGroup, L.P. and certain of its North American subsidiaries filed for bankruptcy protection. At that time, certain SemGroup L.P. entities were purchasing a portion of our oil production. As a result of the bankruptcy filing, we recorded bad debt expense of $16.6 million as of December 31, 2008. In 2009, we sold a portion of our SemGroup L.P. administrative claim, at which time we recorded a recovery of bad debt expense of $5.2 million.

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Change in Net Profits Plan liability. For 2010, this non-cash item was a $34.4 million benefit compared to a $7.1 million benefit for 2009. Payments made or accrued in 2010 as part of allocating the proceeds received from divestitures decreased the estimated liability for the future amounts to be paid to plan participants.
Unrealized and realized derivative (gain) loss. We recognized a loss of $8.9 million in 2010 compared to a loss of $20.5 million for 2009. This non-cash item is driven by the change in the value of our derivative position, as well as the portion of that position that is considered ineffective for accounting purposes.
Other operating expense. Other expense decreased $10.5 million to $3.0 million in 2010 compared with $13.5 million in 2009. During 2009, we incurred $1.5 million of expense related to the assignment of a drilling rig contract in our Rocky Mountain region and incurred a loss related to hurricanes of $8.3 million.
Income tax (expense) benefit. Income tax expense totaled $118.1 million for 2010 compared to a tax benefit of $60.1 million for 2009, resulting in effective tax rates of 37.5 percent and 37.7 percent, respectively. The effective rate change from 2009 primarily reflects changes in the mix of the highest marginal state tax rates, anticipated utilization of state tax net operating losses, and differing effects of other permanent differences, including percentage depletion. Our current income tax expense in 2010 was $3.5 million compared to current income tax benefit of $20.4 million in 2009. These amounts are three percent and 34 percent, respectively, of the total income tax expense or benefit for each period.

Qualified property placed in service in 2009 and 2010, up to September 8, 2010, was eligible for 50 percent bonus depreciation as a result of tax laws passed in 2008 and 2010. Qualified property placed in service after September 8, 2010, was eligible for 100 percent bonus depreciation. Because we are currently in an accelerated development mode on several of our unconventional projects we will not receive much of a current benefit resulting solely from this deduction. However, making the respective elections for 2010 accelerates deductions impacting our alternative minimum tax calculations in future years providing us with an anticipated opportunity, given current development expectations, to limit the impact of alternative minimum tax on the calculation of current income tax expense in those years. The amounts of current income tax expense reported above reflect our election to utilize bonus depreciation for both years. The benefit of bonus depreciation in 2010 was limited by alternative minimum tax calculations related to intangible drilling costs. Our 2009 current income tax benefit reflects creation of a net operating loss due in part to bonus depreciation which we carried back to 2005 to obtain a refund.

Overview of Liquidity and Capital Resources

We believe we have sufficient liquidity and capital resources to execute our business plans for the foreseeable future.

Sources of cash

Our primary sources of liquidity are the cash flows provided by our operating activities, use of our credit facility, divestitures of properties, and other financing alternatives, including accessing capital markets. From time to time, we may be able to enter into carrying cost funding and sharing arrangements with third parties for particular exploration and/or development programs. All of our sources of liquidity can be impacted by the general condition of the broad economy and by fluctuations in commodity prices, operating costs, and volumes produced, all of which affect us and our industry. We have no control over the market prices for oil, gas, or NGLs, although we are able to influence the amount of our realized revenues from our oil, gas, and NGL sales through the use of derivative contracts as part of our commodity price risk management program. The borrowing base on our credit facility could be reduced as a result of lower commodity prices or divestitures of producing properties. Historically, decreases in commodity prices have limited our industry's access to the capital markets.

We also consummated our Acquisition and Development Agreement with Mitsui that funds, or carries, 90 percent of certain for the drilling and completion of Eagle Ford shale wells in our non-operated Eagle Ford shale position until $680.0 million has been expended on our behalf. This carry is expected to be realized over the next three to four years.

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In 2012, we expect cash flow from operations and divestiture proceeds will fund the majority of our capital program. Our credit facility, which was undrawn as of year-end, will be used to fund the remaining balance of our capital program. Although we expect our cash flow, expected divestiture proceeds, and available borrowing capacity under our credit facility will be sufficient to fund our current capital program, accessing the capital markets or the use of other financing alternatives are available options. We will continue to evaluate our property base to identify and divest properties we consider non-core to our strategic goals.

Current proposals to fund the federal government budget include eliminating or reducing current tax deductions for intangible drilling costs, the domestic production activities deduction, and percentage depletion. Legislation modifying or eliminating these deductions would have the immediate effect of reducing operating cash flows thereby reducing funding available for our exploration and development capital programs and those of our peers in the industry. These funding reductions could have a significant adverse effect on drilling in the United States for a number of years.

Credit facility

In May 2011, we entered into our Fourth Amended and Restated Credit Agreement for a $2.5 billion senior secured revolving credit facility having a scheduled maturity date of May 27, 2016. This credit facility replaced our prior $1.0 billion senior secured revolving credit facility. The initial borrowing base for the new credit facility was $1.3 billion, which was subsequently increased as part of our normal redetermination process to $1.4 billion in the third quarter of 2011, and reduced by approximately 25 percent of the aggregate principal amount of our 6.50% Senior Notes, to $1.3 billion in the fourth quarter of 2011. Our lenders have agreed to an aggregate commitment amount of $1.0 billion as of December 31, 2012. The borrowing base is redetermined semi-annually by our lenders. We believe that the commitment amount is sufficient to meet our anticipated liquidity and operating needs. Through the filing date of this report, we have experienced no issues drawing upon our credit facility. No individual bank participating in the credit facility represents more than ten percent of the lending commitments under the credit facility.

We had no borrowings outstanding under this facility as of December 31, 2011, and February 16, 2012. We had two letters of credit outstanding under our credit facility, totaling $608,000, as of December 31, 2011, and February 16, 2012. Letters of credit reduce the amount available under the credit facility on a dollar-for-dollar basis. As a result, we had $999.4 million of available borrowing capacity under this facility as of December 31, 2011, and February 16, 2012. Our daily weighted-average credit facility debt balances for the years ended December 31, 2011, and 2010, were $10.7 million and $54.6 million, respectively. Borrowings under our credit facility are secured by mortgages on substantially all of our oil and gas properties. As of December 31, 2011, and the filing date of this report, we were in compliance with all financial and non-financial covenants under our credit facility. Please refer to Note 5 – Long-term Debt in Part II, Item 8 of this report for our borrowing base utilization grid.

Senior Notes

In the first quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.625% Senior Notes at par. During the fourth quarter of 2011, we issued $350.0 million in aggregate principal amount of 6.50% Senior Notes at par. Please refer to Note 5 – Long-term Debt in Part II, Item 8 of this report for additional discussion.

Weighted-average interest rates

Our weighted-average interest rates in the current and prior year include cash interest payments, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs. Our weighted-average interest rates for the years ended December 31, 2011, 2010, and 2009, were 8.5 percent, 8.3 percent and 5.4 percent, respectively. The increase in our weighted-average interest rate from 2010 is the result of adding higher interest rate debt in 2011, with higher fixed charges, and increased deferred financing costs. Our weighted-average

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borrowing rates for the years ended December 31, 2011, 2010, and 2009, were 5.2 percent, 2.8 percent, and 2.9 percent, respectively. Our weighted-average borrowing rates include cash interest payments, and excludes, cash fees paid on the unused portion of the credit facility's aggregate commitment amount, letter of credit fees, amortization of the convertible notes debt discount, and amortization of deferred financing costs.

We are subject to customary covenants under our credit facility, including limitations on dividend payments and requirements to maintain certain financial ratios, which include debt to consolidated earnings before interest, taxes, depreciation, depletion, amortization, and exploration expense of less than 4.0 to 1.0 and an adjusted current ratio, as defined by our credit agreement, of no less than 1.0. As of December 31, 2011, our debt to EBITDAX ratio and adjusted current ratio as defined by our credit agreement, were 1.11 and 3.04, respectively. As of the filing date of this report, we are in compliance with all financial and non-financial covenants under our credit facility.

Uses of cash

We use cash for the acquisition, exploration, and development of oil and gas properties, and for the payment of debt obligations, trade payables, overhead, income taxes, and stockholder dividends. Expenditures for the exploration and development of oil and gas properties are the primary use of our capital resources. During 2011, we spent $1.6 billion for exploration, development capital expenditures, and leasehold acquisition. These amounts differ from the cost incurred amounts based on the timing of cash payments associated with these activities as compared to the accrual-based activity upon which the costs incurred amounts are presented.

The amount and allocation of future capital expenditures will depend upon a number of factors including the number and size of available economic acquisitions and drilling opportunities, our cash flows from operating, investing and financing activities, and our ability to assimilate acquisitions and execute our drilling program. In addition, the impact of oil, natural gas, and NGL prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements and other factors.

We may from time to time repurchase certain amounts of our outstanding debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in open market transactions, privately negotiated transactions, or otherwise. Any such repurchases or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors. The amounts involved in any such transaction may be material.

In 2011, we paid $6.4 million in dividends to our stockholders, which constitutes an annual dividend of $0.10 per share. Our intention is to continue to make dividend payments for the foreseeable future, subject to our future earnings, our financial condition, credit facility and other covenants, and other factors which could arise. Payment of future dividends remains at the discretion of the Board of Directors.

As of the filing date of this report, our Board has authorized us to repurchase up to 3,072,184 shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of our credit facility and the indentures governing our 6.625% Senior Notes and 6.50% Senior Notes, compliance with securities laws, and the terms and provisions of our stock repurchase program. There were no share repurchases in 2011, and we currently do not plan to repurchase shares in 2012.

On April 1, 2012, all or a portion of our outstanding 3.50% Senior Convertible Notes can be put to us at the option of the respective noteholders. If the notes are put to us on that date, we have the option of paying the purchase price in cash, shares of our common stock, or any combination thereof. On or after April 6, 2012, we will have the option of redeeming all or a portion of the outstanding notes for cash. The notes are convertible into shares of our common stock under certain circumstances, including if they are called for redemption, and we may elect to settle conversion obligations in cash, shares of our common stock, or a combination thereof. Depending on the then current trading level of our common stock and our liquidity position, we may elect to redeem the 3.50%

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Convertible Notes in 2012. The closing price of our common stock exceeded the conversion trigger price of $70.75 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day for the quarters ended March 31, 2011, and December 31, 2011. However, none of the holders opted to convert their 3.50% Senior Convertible Notes during the second quarter of 2011. The notes will be convertible during the first quarter of 2012.
The following table presents amounts and percentage changes between years in net cash flows from our operating, investing, and financing activities. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part II, Item 8 of this report.

	As of and for the Years Ended December 31,			Amount of Changes Between		Percent of Change Between	
	2011	2010	2009	2011/2010	2010/2009	2011/2010	2010/2009
	(in millions)						
Net cash provided by operating activities	$760.5	$497.1	$436.1	$263.4	$61.0	53 %	14 %
Net cash (used in) investing activities	$(1,264.9)	$(361.6)	$(304.1)	$(903.3)	$(57.5)	250 %	19 %
Net cash provided by (used in) financing activities	$618.5	$(141.1)	$(127.5)	$759.6	$(13.6)	(538)%	11 %

Analysis of cash flow changes between 2011 and 2010

Operating activities. Cash received from oil, gas, and NGL production revenues, net of derivative cash settlements of $46.4 million, increased $409.4 million to $1.2 billion for the year ended December 31, 2011. The increase was the result of a 50 percent increase in production revenue including derivative cash settlements. Additionally, cash paid for lease operating expenses in 2011 increased $26.5 million compared with 2010. We received $4.0 million in income tax refunds in 2011 compared to $25.6 million received during 2010.
Investing activities. Cash used for investing activities was $1.3 billion for the year ended December 31, 2011, compared with $361.6 million for the same period in 2010. Cash spent on 2011 capital expenditures increased $964.8 million, or 144 percent, to $1.6 billion. This increase in capital and exploration activities was financed mainly by higher cash flows available from operating activities, divestiture proceeds, and proceeds from the issuance of our 6.625% Senior Notes and 6.50% Senior Notes. Proceeds received from divestitures increased $53.0 million to $364.5 million for the year ended December 31, 2011, due to an increase in the size of the divestiture packages.
Financing activities. Net repayments to our credit facility decreased $92.0 million for the year ended December 31, 2011, compared to 2010 as our strong cash position throughout 2011 resulted in decreased borrowings. After deducting aggregate fees of $15.8 million, we received aggregate net proceeds of $684.2 million due to the issuance of our 6.625% Senior Notes and 6.50% Senior Notes during 2011. We spent $8.7 million on debt issuance costs for our amended credit facility during the year ended December 31, 2011.
Analysis of cash flow changes between 2010 and 2009

Operating activities. Cash received from oil and gas production revenues, net of the realized effects of derivative cash settlements, increased $84.6 million to $836.4 million for the year ended December 31, 2010. The increase was the result of a one percent increase in production and a 13 percent increase in our net realized price after derivative cash settlements, resulting in a 14 percent increase in production revenue. Included in the 2010 oil and gas production revenue amounts was $23.5 million of net realized hedging gains. Additionally, cash paid for lease operating expenses in 2010 decreased $29.2 million compared with 2009. We received $25.6 million in income tax refunds in 2010 compared to $9.9 million received during 2009.

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Investing activities. Cash used for investing activities was $361.6 million for the year ended December 31, 2010, compared with $304.1 million for the same period in 2009. We received proceeds of $311.5 million primarily from the sale of non-strategic properties located in our Rocky Mountain and Permian regions. The $39.9 million of proceeds from the sale of oil and gas properties received in 2009 related primarily to the sale of non-strategic properties located in our Rocky Mountain region that were divested of in the fourth quarter of 2009. Cash outflows for 2010 capital expenditures increased $289.0 million, or 76 percent, to $668.3 million. This was due to increased drilling activity as a result of more favorable commodity prices, an improved overall macro-economic environment, and our drilling activities in our Eagle Ford shale play. We received $16.8 million in proceeds from an insurance settlement relating to Hurricane Ike for the year ended December 31, 2009, but no material insurance proceeds were received in 2010.

Financing activities. Net repayments to our credit facility increased $28.0 million for the year ended December 31, 2010, compared to 2009. We spent $11.1 million on debt issuance costs for our amended credit facility during the year ended December 31, 2009. We did not incur any debt issuance costs in 2010. We received $3.3 million more in proceeds from the sale of common stock in 2010, than in 2009.

Commodity Price Risk and Interest Rate Risk

We are exposed to market risk, including the effects of changes in oil, gas, and NGL commodity prices and changes in interest rates. Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, and short-term investments, and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 3.50% Senior Convertible Notes, 6.625% Senior Notes, or 6.50% Senior Notes, but do affect their fair market value.

For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt typically approximates its fair value. We had no floating-rate debt outstanding as of December 31, 2011. Our fixed-rate debt outstanding, net of debt discount, at this same date was $985.1 million. As of December 31, 2011, we do not have any interest rate hedges in place to mitigate potential interest rate risks.

Because we produce and sell oil, gas, and NGLs, our financial results are affected when prices for these commodities fluctuate. The following table reflects our estimate of the effect on net cash flows from operations of a ten percent change in our adjusted price for oil, gas, or NGLs, and in combination for the years presented, inclusive of the impact of derivative cash settlements. These amounts have been reduced by the effective income tax rate applicable to each period since a reduction in revenue would reduce income taxes. General and administrative expenses have not been adjusted. To fund the capital expenditures we incurred in those years we would have been required to utilize amounts under our credit facility as a source of funds. In each of these years we would have had sufficient unused borrowing capacity available under our credit facility to meet this contingency without reducing or eliminating expenditures or altering our growth strategy.

The table below shows the effect of a ten percent decrease in adjusted price on net cash flow from operations:

	For the Years Ended December 31,		
	2011	2010	2009
	(in millions)		
Oil	$(73.7)	$(48.7)	$(29.5)
Natural Gas	(37.9)	(30.5)	(11.9)
NGLs	(18.4)	—	—
Total	$(130.0)	$(79.2)	$(41.4)

We enter into commodity derivative contracts in order to reduce the impact of fluctuations in commodity

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prices. Please refer to Note 10 – Derivative Financial Instruments of Part II, Item 8 of this report for additional information about our oil, gas, and NGL derivative contracts, and additional information is below under the caption Summary of Oil, Gas, and NGL Derivative Contracts in Place. We do not anticipate significant changes in existing derivative contract transactions.

Summary of Oil, Gas, and NGL Derivative Contracts in Place

Our oil, gas, and NGLs derivative contracts include costless swaps and costless collar arrangements. All contracts are entered into for other-than-trading purposes. Please refer to Note 10 – Derivative Financial Instruments in Part II, Item 8 of this report for additional information regarding accounting for our derivative transactions. Commodity derivatives are an important part of our financial risk management program. The amount of commodity derivative contracts we enter into is driven by the amount of debt on our accompanying consolidated balance sheets and the level of capital and long-term commitments we have made, as well as considerations of other factors.

As of December 31, 2011, our commodity derivative contracts through the second quarter of 2014 totaled 7.5 million Bbls of oil, 56.7 million MMBtu of gas, and 1.3 million Bbls of NGLs. As of February 16, 2012, the Company had commodity derivative contracts in place through the fourth quarter of 2014 for a total of 11.0 million Bbls of oil, 77.9 million MMBtu of gas, and 1.5 million Bbls of NGLs.

In a typical commodity swap agreement, if the agreed-upon published third-party index price is lower than the swap fixed price, we receive the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. We pay the difference between the agreed upon contracted ceiling price and the index price if the index price is above the contracted ceiling price. No amounts are paid or received if the index price is between the contracted floor and ceiling prices.

The following tables describe the approximate volumes, average contract prices, and fair value of contracts we have in place as of December 31, 2011.

Oil contracts

Oil Swaps:

Contract Period	NYMEX WTI Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2011 (Liability)	
	(Bbls)	(per Bbl)	(in millions)	
First quarter 2012	569,000	$84.15	$(8.5	)
Second quarter 2012	524,000	$84.19	(7.9	)
Third quarter 2012	489,000	$83.87	(7.2	)
Fourth quarter 2012	463,000	$87.08	(5.0	)
2013	616,000	$88.22	(4.8	)
2014	661,000	$91.72	(0.9	)
All oil swaps	3,322,000		$(34.3	)

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Oil Collars:

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2011 Assets (Liability)
	(Bbls)	(per Bbl)	(per Bbl)	(in millions)
First quarter 2012	391,000	$76.58	$109.96	$(0.5)
Second quarter 2012	372,000	$76.55	$109.88	(0.9)
Third quarter 2012	347,000	$76.45	$109.70	(0.9)
Fourth quarter 2012	325,000	$76.34	$109.60	(0.8)
2013	2,147,000	$75.84	$109.81	(4.2)
2014	560,000	$80.00	$116.05	1.2
All oil collars	4,142,000			$(6.1)

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Natural Gas Contracts
Natural Gas Swaps:

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2011 Asset
	(MMBtu)	(per MMBtu)	(in millions)
First quarter 2012	7,930,000	$5.15	$17.4
Second quarter 2012	7,140,000	$4.77	12.6
Third quarter 2012	6,510,000	$4.95	11.7
Fourth quarter 2012	6,020,000	$5.20	10.7
2013	13,810,000	$5.05	17.0
2014	2,910,000	$5.42	3.3
All natural gas swaps*	44,320,000		$72.7

*Natural gas swaps are comprised of IF ANR OK (1%), IF CIG (2%), IF El Paso Permian (2%), IF HSC (8%), IF NGPL MidCont. (1%), IF NGPL TXOK (6%), IF NNG Ventura (1%), IF PEPL (19%), IF Reliant N/S (34%), and IF TETCO STX (26%).

Natural Gas Collars:

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at December 31, 2011 Asset
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in millions)
2013	6,650,000	4.39	5.34	$4.8
2014	5,734,000	4.38	5.36	2.7
All natural gas collars*	12,384,000			$7.5

*Natural gas collars are comprised of IF HSC (18%), IF NGPL TXCO (18%), IF Reliant N/S (29%), and IF TETCO STX (35%).
Natural Gas Liquid Contracts
NGL Swaps:

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at December 31, 2011 (Liability)	
	(Bbls)	(per Bbl)	(in millions)	
First quarter 2012	349,000	$46.04	$(3.4	)
Second quarter 2012	314,000	$45.64	(2.2	)
Third quarter 2012	287,000	$47.85	(1.1	)
Fourth quarter 2012	266,000	$47.72	(1.0	)
2013	84,000	$44.95	(0.9	)
All NGL swaps*	1,300,000		$(8.6	)

*NGL swaps are comprised of OPIS Mont. Belvieu LDH Propane (32%), OPIS Mont. Belvieu Purity Ethane (41%), OPIS Mont. Belvieu NON-LDH Isobutane (5%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (11%), and OPIS Mont. Belvieu NON-LDH Normal Butane (11%).

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Commodity Derivative Contracts Entered into After December 31, 2011

The following tables include all commodity derivative contracts entered into subsequent to December 31, 2011, through February 16, 2012:

Oil Collars:

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price
	(Bbls)	(per Bbl)	(per Bbl)
First quarter 2012	323,000	$85.00	$115.90
Second quarter 2012	371,000	$85.00	$115.90
Third quarter 2012	291,000	$85.00	$115.90
Fourth quarter 2012	241,000	$85.00	$115.90
2013	720,000	$85.00	$111.00
2014	1,614,000	$85.00	$105.12
All oil collars	3,560,000		

Natural Gas Swaps:

Contract Period	Volumes	Weighted-Average Contract Price
	(MMBtu)	(per MMBtu)
Fourth quarter 2012	2,404,000	$2.98
2013	6,699,000	$3.43
2014	12,044,000	$3.95
All natural gas swap contracts	21,147,000	

*Natural gas swaps are comprised of IF HSC (76%), IF NGPL TXOK (5%), IF PEPL (10%), IF Reliant N/S (9%).

NGL Swaps:

Contract Period	Volumes	Weighted-Average Contract Price
	(Bbls)	(per Bbl)
First quarter 2012	61,000	$83.11
Second quarter 2012	73,000	$83.07
Third quarter 2012	59,000	$83.09
Fourth quarter 2012	50,000	$83.06
All NGL swap contracts	243,000	

*NGL swaps are comprised of OPIS Mont. Belvieu NON-LDH Isobutane (36%), OPIS Mont. Belvieu NON-LDH Natural Gasoline (36%), and OPIS Mont. Belvieu NON-LDH Normal Butane (28%).

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Schedule of Contractual Obligations

The following table summarizes our future estimated principal payments and minimum lease payments for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$1,391.0	$347.1	$91.9	$91.9	$860.1
Derivative liability	55.9	42.9	13.0	—	—
Net Profits Plan	105.8	20.8	37.6	32.0	15.4
Delivery commitments	893.6	24.1	134.3	190.3	544.9
Operating leases and contracts	205.4	106.9	74.0	7.7	16.8
Other	18.6	6.5	11.4	0.3	0.4
Total	$2,670.3	$548.3	$362.2	$322.2	$1,437.6

The long-term debt line in this table includes $287.5 million for the 3.50% Senior Convertible Notes, $350.0 million for the 6.625% Senior Notes, and $350.0 million for the 6.50% Senior Notes. The long-term debt balance also includes accrued interest of $173.0 million and $228.0 million for the 6.625% Senior Notes and the 6.50% Senior Notes, respectively. Additionally, we have assumed that we will redeem the 3.50% Senior Convertible Notes during 2012. Accordingly, $2.5 million of interest payments related to the 3.50% Senior Convertible Notes are included in long-term debt in the table above. The actual payments under our revolving credit facility will vary significantly. We had no outstanding borrowings under our credit facility as of December 31, 2011.

The above table includes estimated oil, gas, and NGL derivative payments of $55.9 million based on future market prices as of December 31, 2011. This amount represents only the liability portion of the marked-to-market value of our commodity derivatives at December 31, 2011; it does not include estimated oil, gas, and NGL derivative receipts based on December 31, 2011, market prices. This amount varies from the fair value of our derivative assets and liabilities presented on the accompanying consolidated balance sheets, as the fair value of such derivative contracts considers time value, volatility, and the risk of non-performance for us and for our counterparties. Both the marked-to-market value and fair value will change as oil, gas, and NGL commodity prices change. The overall fair value of our commodity derivative portfolio as of December 31, 2011, was a net asset of $31.2 million.

The table also includes $105.8 million in other long-term liabilities that represents six years of undiscounted forecasted payments for the Net Profits Plan. Payments are expected to gradually decrease for the years beyond what is shown in this table. The amounts recorded on the accompanying consolidated balance sheets reflect all future Net Profits Plan payments and the impact of discounting, and therefore differ from the amounts disclosed in this table. The variability in the amount of payments will be a direct reflection of commodity prices, production rates, capital expenditures, and operating costs in future periods. Predicting the timing and amounts of payments associated with this liability is contingent upon estimates of appropriate discount factors, adjusting for risk and time value, and upon a number of factors we cannot control.

The other line in the table includes the remaining funded portion of our estimated pension liability of $15.5 million, even though we recognize that we cannot accurately determine the timing of future payments. We are expected to make contributions to the Pension Plan in 2012 of $4.9 million. We made contributions of $5.3 million and in 2011.

In addition to the amounts included in the table above, we entered into a capital project in 2011 for the development of infrastructure in our non-operated Eagle Ford shale play, which will extend through 2013. Pursuant to the terms of our agreement for the construction, ownership, and operation of these assets, we are required to pay our portion of the expenses. Based on current estimates, we do not expect our commitment costs to exceed $75.0 million over the duration of the agreement.

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We have excluded asset retirement obligations because we are not able to accurately predict the precise timing of these amounts.

Please refer to Note 8 – Pension Benefits, Note 9 – Asset Retirement Obligations, and Note 7 – Compensation Plans, Note 10 – Derivative Financial Instruments, and Note 6 – Commitments and Contingencies in Part II, Item 8 of this report for additional discussion regarding our pension liability, asset retirement obligations, Net Profits Plan liability, derivative contracts, operating leases, and gathering, processing, and transportation through-put commitments.

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As of December 31, 2011, we have not been involved in any unconsolidated SPE transactions.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity is consolidated into our consolidated financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these consolidated financial statements in conformity with accounting principles generally accepted in the United States requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses as well as the disclosure of contingent assets and liabilities as of the date of our financial statements. We base our estimates on historical experience and various other sources that we believe to be reasonable under the circumstances. Actual results may differ from the estimates we calculate due to changes in circumstances, global economics and politics, and general business conditions. A summary of our significant accounting policies is detailed in Note 1 – Summary of Significant Accounting Policies in Part II, Item 8 of this report. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and which require the application of significant management judgment.

Oil and gas reserve quantities. Our estimated reserve quantities and future net cash flows are critical to the understanding of the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in our financial statements including the calculations of depletion and impairment of proved oil and gas properties and the estimate of our Net Profits Plan liability. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a ten percent discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves, including using independent reserve engineering consultants. We expect that periodic reserve estimates will change in the future as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves at December 31 and June 30 of each year. For purposes of depletion and impairment, reserve quantities are adjusted at all interim periods for the estimated impact of additions and dispositions. Changes in depletion or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change. Please refer to Supplemental Oil and Gas Information in Part II, Item 8 of this report.

The following table presents information about reserve changes from period to period that due to items we

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do not control, such as price, and from changes due to production history and well performance. These changes do not require a capital expenditure on our part, but may have resulted from capital expenditures we incurred to develop other estimated proved reserves.

	For the Years Ended December 31,		
	2011	2010	2009
	BCFE Change	BCFE Change	BCFE Change
Revisions resulting from price changes	(25.3)	42.6	12.0
Revisions resulting from performance	36.8	(17.9)	(61.6)
Total	11.5	24.7	(49.6)

As previously noted, commodity prices are volatile, and estimates of reserves are inherently imprecise. Consequently, we expect to continue experiencing these types of changes. Please refer to additional reserves discussion under Overview of the Company.

The following table reflects the estimated BCFE change and percentage change to our total reported reserve volumes from the described hypothetical changes:

	For the Years Ended December 31,					
	2011		2010		2009	
	BCFE Change	Percentage Change	BCFE Change	Percentage Change	BCFE Change	Percentage Change
A 10% decrease in SEC pricing	(22.2)	(2)%	(13.9)	(1)%	(25.1)	(3)%
A 10% decrease in proved undeveloped reserves	(41.5)	(3)%	(29.7)	(3)%	(14.2)	(2)%

The table above solely reflects the impact of a ten percent change in SEC pricing or decrease in proved undeveloped reserves and does not include additional impacts to our proved reserves that may result from our internal intent to drill hurdles. Additional reserve information can be found in the reserve table and discussion included in Items 1 and 2 of Part I of this report, and in Supplemental Oil and Gas Disclosures of Part II, Item 8 of this report.

Successful efforts method of accounting. Accounting principles generally accepted in the United States provide for two alternative methods for the oil and gas industry to use in accounting for oil and gas producing activities. These two methods are generally known in our industry as the full cost method and the successful efforts method. Both methods are widely used. The methods are different enough that in many circumstances the same set of facts will provide materially different financial statement results within a given year. We have chosen the successful efforts method of accounting for our oil and gas producing activities. A more detailed description is included in Note 1 - Summary of Significant Accounting Policies of Part II, Item 8 of this report.

Revenue recognition. Our revenue recognition policy is significant because revenue is a key component of our results of operations and our forward-looking statements contained in our analysis of liquidity and capital resources. We derive our revenue primarily from the sale of produced oil, gas, and NGLs. We report revenue as the gross amounts we receive before taking into account production taxes and transportation costs, which are reported as separate expenses. Revenue is recorded in the month our production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month we make estimates of the amount of production delivered to the purchaser and the price we will receive. We use our knowledge of our properties, their historical performance, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between our estimates and the actual amounts received are recorded in the month payment is received. A ten percent change in our year-end revenue accrual would have impacted net income before tax by $14.9 million in 2011.

Change in Net Profits Plan Liability. We record the estimated liability of future payments for our Net Profits Plan. The estimated liability is calculated based on a number of assumptions, including estimates of proved reserves, estimated future capital, present value discount factors, pricing assumptions, and overall market conditions. Please refer to Note 11 - Fair Value Measurements in Part II, Item 8 of this report for additional discussion.

Asset retirement obligations. We are required to recognize an estimated liability for future costs associated with the abandonment of our oil and gas properties. We base our estimate of the liability on our historical experience in abandoning oil and gas wells projected into the future based on our current understanding of federal and state regulatory requirements. Our present value calculations require us to estimate the economic lives of our properties, assume what future inflation rates apply to external estimates, and determine what credit-adjusted risk-free discount rate to use. The impact to the accompanying consolidated statements of operations from these estimates is reflected in our depreciation, depletion, and amortization calculations and occurs over the remaining life of our respective oil and gas properties. Please refer to Note 9 – Asset Retirement Obligations in Part II, Item 8 of this report.

Impairment of oil and gas properties. Our proved oil and gas properties are recorded at cost. We evaluate our proved properties for impairment at least annually and when events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our oil and gas properties and compare these undiscounted cash flows to the the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures, and discount rates.

Unproved oil and gas properties are assessed periodically for impairment on a lease-by-lease basis based on the remaining lease terms, drilling results, commodity price outlook, and future capital allocations. An impairment allowance is provided on unproven property when we determine that the property will not be developed or the carrying value will not be realized. Please refer to section Impairment of Proved and Unproved Properties in Note 1 - Summary of Significant Accounting Policies in Part II, Item 8 of this report for impairment results.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and gas price volatility. The accounting treatment for the change in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is designated as a hedge. Effective January 1, 2011, we elected to de-designate all of our commodity derivatives that had previously been designated as cash flow hedges as of December 31, 2010, and have elected to discontinue hedge accounting prospectively. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in accumulated other comprehensive loss until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the statement of income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative's fair value and any ineffective portion of the derivative instrument's change in fair value is recognized immediately in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, and time to maturity and credit risk. The values we report in our financial statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Income taxes. We provide for deferred income taxes on the difference between the tax basis of an asset or

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liability and its carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in predicting when these events may occur and whether recovery of an asset is more likely than not. Additionally, our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we use and actual amounts we report are recorded in the periods in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery and liability settlement could have an impact on our results of operations. A one percent increase and decrease in our effective tax rate would have changed our calculated income tax expense by $3.5 million and $3.2 million, respectively, for the year ended December 31, 2011.

Accounting Matters

Please refer to the section entitled Recently Issued Accounting Standards under Note 1 – Summary of Significant Accounting Policies for additional information on the recent adoption of new authoritative accounting guidance in Part II, Item 8 of this report.

Environmental

We believe we are in substantial compliance with environmental laws and regulations and do not currently anticipate that material future expenditures will be required under the existing regulatory framework. However, environmental laws and regulations are subject to frequent changes and we are unable to predict the impact that compliance with future laws or regulations, such as those currently being considered as discussed below, may have on future capital expenditures, liquidity, and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. For additional information about hydraulic fracturing and related environmental matters, see Risk Factors – Risks Related to Our Business – Proposed federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other ‘‘greenhouse gases’’ present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including petroleum refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require

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us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

In terms of opportunities, the regulation of greenhouse gas emissions and the introduction of alternative incentives, such as enhanced oil recovery, carbon sequestration and low carbon fuel standards, could benefit us in a variety of ways. For example, although climate change legislation could reduce the overall demand for the oil and natural gas that we produce, the relative demand for natural gas may increase since the burning of natural gas produces lower levels of emissions than other readily available fossil fuels such as oil and coal. In addition, if renewable resources, such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent electricity supply. Also, if states adopt low-carbon fuel standards, natural gas may become a more attractive transportation fuel. Approximately 59 and 65 percent of our production on an MCFE basis in 2011 and 2010, respectively, was natural gas. Market-based incentives for the capture and storage of carbon dioxide in underground reservoirs, particularly in oil and natural gas reservoirs, could also benefit us through the potential to obtain greenhouse gas emission allowances or offsets from or government incentives for the sequestration of carbon dioxide.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information required by this item is provided under the captions Commodity Price Risk and Interest Rate Risk and Summary of Oil, Gas, and NGL Derivative Contracts in Place in Item 7 above and is incorporated herein by reference.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SM Energy Company and Subsidiaries
Denver, Colorado

We have audited the accompanying consolidated balance sheets of SM Energy Company and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income (loss), and cash flows 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 the 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, such consolidated financial statements present fairly, in all material respects, the financial position of SM Energy Company and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of oil and gas reserve estimation and related required disclosures in 2009 with the implementation of new accounting guidance.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2012, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2012

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands, except share amounts)

	December 31, 2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents	$119,194	$5,077
Accounts receivable (note 2)	210,368	163,190
Refundable income taxes	5,581	8,482
Prepaid expenses and other	68,026	45,522
Derivative asset	55,813	43,491
Deferred income taxes	4,222	8,883
Total current assets	463,204	274,645
Property and equipment (successful efforts method), at cost:		
Land	1,548	1,491
Proved oil and gas properties	4,378,987	3,389,158
Less - accumulated depletion, depreciation, and amortization	(1,766,445)	(1,326,932)
Unproved oil and gas properties	120,966	94,290
Wells in progress	273,428	145,327
Materials inventory, at lower of cost or market	16,537	22,542
Oil and gas properties held for sale	246	86,811
Other property and equipment, net of accumulated depreciation of $23,985 in 2011 and $15,480 in 2010	71,369	21,365
Total property and equipment, net	3,096,636	2,434,052
Other noncurrent assets:		
Derivative asset	31,062	18,841
Restricted cash (note 1)	124,703	—
Other noncurrent assets	83,375	16,783
Total other noncurrent assets	239,140	35,624
Total Assets	$3,798,980	$2,744,321
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses (note 2)	$456,999	$417,654
Derivative liability	42,806	82,044
Other current liabilities	6,000	2,355
Total current liabilities	505,805	502,053
Noncurrent liabilities:		
Long-term credit facility	—	48,000
3.50% Senior Convertible Notes, net of unamortized discount of $2,431 in 2011 and $11,827 in 2010	285,069	275,673
6.625% Senior Notes	350,000	—
6.50% Senior Notes	350,000	—
Asset retirement obligation	87,167	69,052
	1,277	2,119

Asset retirement obligation associated with oil and gas properties held for sale		
Net Profits Plan liability (note 11)	107,731	135,850
Deferred income taxes	568,263	443,135
Derivative liability	12,875	32,557
Other noncurrent liabilities	67,853	17,356
Total noncurrent liabilities	1,830,235	1,023,742
Commitments and contingencies (note 6)		
Stockholders' equity:		
Common stock, $0.01 par value - authorized: 200,000,000 shares; issued: 64,145,482 shares in 2011 and 63,412,800 shares in 2010; outstanding, net of treasury shares: 64,064,415 shares in 2011 and 63,310,165 shares in 2010	641	634
Additional paid-in capital	216,966	191,674
Treasury stock, at cost: 81,067 shares in 2011 and 102,635 shares in 2010	(1,544)	(423)
Retained earnings	1,251,157	1,042,123
Accumulated other comprehensive loss	(4,280)	(15,482)
Total stockholders' equity	1,462,940	1,218,526
Total Liabilities and Stockholders' Equity	$3,798,980	$2,744,321

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	For the Years Ended December 31,		
	2011	2010	2009
Operating revenues and other income:			
Oil, gas, and NGL production revenue	$1,332,392	$836,288	$615,953
Realized hedge (loss) gain (note 10)	(20,707)	23,465	140,648
Gain on divestiture activity (note 3)	220,676	155,277	11,444
Marketed gas system revenue	69,898	70,110	58,459
Other operating revenue	1,059	7,694	5,697
Total operating revenues and other income	1,603,318	1,092,834	832,201
Operating expenses:			
Oil, gas, and NGL production expense	290,111	195,075	206,800
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	511,103	336,141	304,201
Exploration	53,537	63,860	62,235
Impairment of proved properties	219,037	6,127	174,813
Abandonment and impairment of unproved properties	7,367	1,986	45,447
Impairment of materials inventory	—	—	14,223
General and administrative	118,526	106,663	76,036
Bad debt recovery	—	—	(5,189)
Change in Net Profits Plan liability	(25,477)	(34,441)	(7,075)
Unrealized and realized derivative (gain) loss (note 10)	(37,086)	8,899	20,469
Marketed gas system expense	64,249	66,726	57,587
Other operating expense	17,567	3,027	13,489
Total operating expenses	1,218,934	754,063	963,036
Income (loss) from operations	384,384	338,771	(130,835)
Nonoperating income (expense):			
Interest income	466	321	227
Interest expense	(45,849)	(24,196)	(28,856)
Income (loss) before income taxes	339,001	314,896	(159,464)
Income tax (expense) benefit	(123,585)	(118,059)	60,094
Net income (loss)	$215,416	$196,837	$(99,370)
Basic weighted-average common shares outstanding	63,755	62,969	62,457
Diluted weighted-average common shares outstanding	67,564	64,689	62,457
Basic net income (loss) per common share (note 1)	$3.38	$3.13	$(1.59)
Diluted net income (loss) per common share (note 1)	$3.19	$3.04	$(1.59)

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balances, January 1, 2009	62,465,572	$625	$141,283	(176,987)	$(1,892)	$957,200	$ 65,293	$ 1,162,509
Comprehensive loss, net of tax:								
Net loss	—	—	—	—	—	(99,370)	—	(99,370)
Change in derivative instrument fair value	—	—	—	—	—	—	(35,977)	(35,977)
Reclassification to earnings	—	—	—	—	—	—	(67,344)	(67,344)
Pension liability adjustment	—	—	—	—	—	—	74	74
Total comprehensive loss								(202,617)
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,247)	—	(6,247)
Issuance of common stock under Employee Stock Purchase Plan	86,308	1	1,515	—	—	—	—	1,516
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax cost of RSUs	156,252	1	(1,951)	—	—	—	—	(1,950)
Sale of common stock, including income tax benefit of stock option exercises	189,740	2	1,592	—	—	—	—	1,594
Stock-based compensation expense	1,250	—	18,077	50,094	688	—	—	18,765
Balances, December 31, 2009	62,899,122	$629	$160,516	(126,893)	$(1,204)	$851,583	$ (37,954)	$ 973,570
Comprehensive income, net of tax:								
Net income	—	—	—	—	—	196,837	—	196,837
Change in derivative instrument fair value	—	—	—	—	—	—	16,811	16,811
Reclassification to earnings	—	—	—	—	—	—	6,641	6,641

Pension liability adjustment	—	—	—	—	—	—	(980)	(980)
Total comprehensive income								219,309
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,297)	—	(6,297)
Issuance of common stock under Employee Stock Purchase Plan	52,948	1	1,669	—	—	—	—	1,670
Issuance of common stock upon vesting of RSUs, net of shares used for tax withholdings, including income tax cost of RSUs	113,103	1	(2,094)	—	—	—	—	(2,093)
Sale of common stock, including income tax benefit of stock option exercises	346,377	3	5,621	—	—	—	—	5,624
Stock-based compensation expense	1,250	—	25,962	24,258	781	—	—	26,743
Balances, December 31, 2010	63,412,800	$634	$191,674	(102,635)	$(423)	$1,042,123	$ (15,482)	$1,218,526
Comprehensive income, net of tax:								
Net income	—	—	—	—	—	215,416	—	215,416
Reclassification to earnings	—	—	—	—	—	—	12,997	12,997
Pension liability adjustment	—	—	—	—	—	—	(1,795)	(1,795)
Total comprehensive income								226,618
Cash dividends, $ 0.10 per share	—	—	—	—	—	(6,382)	—	(6,382)
Issuance of common stock under Employee Stock Purchase Plan	41,358	—	2,300	—	—	—	—	2,300
Issuance of common stock upon vesting of RSUs and settlement of PSUs, net of shares used for tax withholdings	278,773	3	(9,976)	—	—	—	—	(9,973)
Sale of common stock, including income tax benefit of stock option exercises	412,551	4	5,023	—	—	—	—	5,027
Stock-based compensation	—	—	27,945	21,568	(1,121)	—	—	26,824

expense								
Balances, December 31, 2011	64,145,482	$641	$216,966	(81,067)	$(1,544)	$1,251,157	$ (4,280)	$ 1,462,940

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the Years Ended December 31, 2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$215,416	$196,837	$(99,370)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Gain on divestiture activity	(220,676)	(155,277)	(11,444)
Depletion, depreciation, amortization, and asset retirement obligation liability accretion	511,103	336,141	304,201
Exploratory dry hole expense	277	289	7,810
Impairment of proved properties	219,037	6,127	174,813
Abandonment and impairment of unproved properties	7,367	1,986	45,447
Impairment of materials inventory	—	—	14,223
Stock-based compensation expense	26,824	26,743	18,765
Bad debt recovery	—	—	(5,189)
Change in Net Profits Plan liability	(25,477)	(34,441)	(7,075)
Unrealized derivative (gain) loss	(62,757)	8,899	20,469
Loss related to hurricanes	—	—	8,301
Amortization of debt discount and deferred financing costs	18,299	13,464	12,213
Deferred income taxes	123,789	114,517	(39,735)
Plugging and abandonment	(5,849)	(8,314)	(26,396)
Other	(6,027)	(3,993)	3,382
Changes in current assets and liabilities:			
Accounts receivable	(41,998)	(47,153)	46,743
Refundable income taxes	2,901	24,291	(19,612)
Prepaid expenses and other	16,376	(35,363)	(6,626)
Accounts payable and accrued expenses	(18,073)	53,198	(4,814)
Excess income tax benefit from the exercise of stock awards	—	(854)	—
Net cash provided by operating activities	760,532	497,097	436,106
Cash flows from investing activities:			
Net proceeds from sale of oil and gas properties	364,522	311,504	39,898
Proceeds from insurance settlement	—	—	16,789
Capital expenditures	(1,633,093)	(668,288)	(379,253)
Acquisition of oil and gas properties	—	(664)	(76)
Receipts from restricted cash related to 1031 exchange	—	—	14,398
Other	3,661	(4,125)	4,152
Net cash used in investing activities	(1,264,910)	(361,573)	(304,092)
Cash flows from financing activities:			
Proceeds from credit facility	322,000	571,559	2,072,500
Repayment of credit facility	(370,000)	(711,559)	(2,184,500)
Debt issuance costs related to credit facility	(8,719)	—	(11,074)
Net proceeds from 6.625% Senior Notes	341,122	—	—
Net proceeds from 6.50% Senior Notes	343,120	—	—

Proceeds from sale of common stock	7,327	6,440	3,110
Dividends paid	(6,382)	(6,297)	(6,247)
Excess income tax benefit from the exercise of stock awards	—	854	—
Other	(9,973)	(2,093)	(1,285)
Net cash provided by (used in) financing activities	618,495	(141,096)	(127,496)
Net change in cash and cash equivalents	114,117	(5,572)	4,518
Cash and cash equivalents at beginning of period	5,077	10,649	6,131
Cash and cash equivalents at end of period	$119,194	$5,077	$10,649

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

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SM ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

Supplemental schedule of additional cash flow information and non-cash investing and financing activities:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Cash paid for interest, net of capitalized interest	$(22,133)	$(13,340)	$(17,884)
Net cash refunded for income taxes	$4,046	$25,578	$9,857

For the years ended December 31, 2011, 2010, and 2009, $214.8 million, $238.5 million, and $109.0 million, respectively, are included as additions to oil and gas properties and accounts payable and accrued expenses. These oil and gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

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SM ENERGY COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Summary of Significant Accounting Policies

Description of Operations

SM Energy is an independent energy company engaged in the acquisition, exploration, exploitation, development and production of oil, gas, and NGLs in onshore North America, with a focus on oil and liquids-rich resource plays.

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") and the instructions to Form 10-K and regulation S-X. Subsidiaries that the Company does not control are accounted for using the equity or cost methods as appropriate. Equity method investments are included in other noncurrent assets in the accompanying consolidated balance sheets ("accompanying balance sheets"). Intercompany accounts and transactions have been eliminated. In connection with the preparation of the consolidated financial statements, the Company evaluated subsequent events after the balance sheet date of December 31, 2011, through the filing date of this report.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of proved oil and gas reserves, assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Estimates of proved oil and gas reserve quantities provide the basis for the calculation of depletion, depreciation, and amortization (“DD&A”), impairment of proved properties, asset retirement obligations, and the Net Profits Plan liability, each of which represents a significant component of the accompanying consolidated financial statements.

Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments.

Restricted Cash

The Company's restricted cash balance represents cash payments received from Mitsui that are contractually restricted to be used solely for development operations pursuant to the Company's Acquisition and Development Agreement with Mitsui and accordingly are classified as non-current assets. Please refer to Note 12- Acquisition and Development Agreement and Carry and Earning Agreement for additional information.

Accounts Receivable and Concentration of Credit Risk

The Company’s accounts receivables consist mainly of receivables from oil and gas purchasers and from joint interest owners on properties the Company operates. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings.

Although diversified among many companies, collectability is dependent upon the financial wherewithal of each individual company and is influenced by the general economic conditions of the industry. Receivables are not collateralized. As of December 31, 2011, and 2010, the Company had no allowance for doubtful accounts recorded.

The Company has accounts in the following locations with two national banks: Denver, Colorado; Shreveport, Louisiana; Houston, Texas; Midland, Texas; and Billings, Montana. The Company has accounts with local banks in Tulsa, Oklahoma and Billings, Montana. The Company's policy is to invest in highly-rated instruments and to limit the amount of credit exposure at each individual institution.

The Company currently uses ten separate counterparties for its oil, gas, and NGL commodity derivatives. The counterparties to the Company's derivative instruments are highly-rated entities with corporate credit ratings at or exceeding A- and Baa1 classifications by Standard & Poor's and Moody's, respectively.

Oil and Gas Producing Activities

In January 2010, the Financial Accounting Standards Board ("FASB") issued oil and gas reserve estimation and disclosure authoritative accounting guidance effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC final rule, " Modernization of Oil and Gas Reporting ", which was also effective for annual reports for fiscal years ending on or after December 31, 2009. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which was developed by several petroleum industry organizations and is a widely accepted standard for the management of petroleum resources. Key revisions include a requirement to use 12-month average pricing determined by averaging the first of the month prices for the preceding 12 months rather than year-end pricing for estimating proved reserves, the ability to include nontraditional resources in reserves, the ability to use new technology for determining proved reserves, and permitting disclosure of probable and possible reserves. The Company adopted these new rules and interpretations as of December 31, 2009.

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either development or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that economic proved reserves have been discovered may take considerable time and judgment. Exploratory dry hole costs are included in cash flows from investing activities as part of capital expenditures within the accompanying consolidated statements of cash flows. The costs of development wells are capitalized whether those wells are successful or unsuccessful.

DD&A of capitalized costs related to proved oil and gas properties is calculated on a pool-by-pool basis using the units-of-production method based upon proved reserves. The computation of DD&A takes into consideration restoration, dismantlement, and abandonment costs as well as the anticipated proceeds from salvaging equipment. As of December 31, 2011, and 2010, the Company's estimated salvage value was $64.1 million and $67.9 million, respectively.

Impairment of Proved and Unproved Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value, which is expected future discounted cash flows, when there is an indication that the carrying costs may not be recoverable. Expected future cash flows are calculated on all developed proved reserves and risk adjusted proved undeveloped, probable, and possible reserves using a discount rate and price forecasts selected by the Company's management. The discount rate is a rate that management believes is representative of current market conditions. The price forecast is based on NYMEX strip pricing for the first five years, adjusted for basis differentials. At the end of the first five years, a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates. An impairment is recorded on unproved property when the Company determines that either the property will not be developed or the carrying value is not realizable.

The Company recorded $219.0 million, $6.1 million, and $174.8 million, of proved property impairments

for the years ended December 31, 2011, 2010, and 2009, respectively. The Company impaired its James Lime, Cotton Valley, and Haynesville assets due to significantly lower natural gas prices in the second half of 2011. The largest portion of the impairment in 2009 related to assets located in the Company's Mid-Continent region that were impacted by lower natural gas prices and wider than normal differentials.

For the years ended December 31, 2011, 2010, and 2009, the Company recorded expense related to the abandonment and impairment of unproved properties of $7.4 million, $2.0 million, and $45.4 million, respectively. The largest components of the 2009 impairment related to acreage located in Mississippi and Oklahoma.

Sales of Proved and Unproved Properties

The partial sale of proved properties within an existing field is accounted for as normal retirement and no gain or loss on divestiture activity is recognized as long as the treatment does not significantly affect the units-of-production depletion rate. The sale of a partial interest in an individual proved property is accounted for as a recovery of cost. A gain or loss on divestiture activity is recognized for all other sales of proved properties and is included in the accompanying consolidated statements of operations ("accompanying statements of operations").

The partial sale of unproved property is accounted for as a recovery of cost when substantial uncertainty exists as to the ultimate recovery of the cost applicable to the interest retained. A gain on divestiture activity is recognized to the extent that the sales price exceeds the carrying amount of the unproved property. A gain or loss on divestiture activity is recognized for all other sales of unproved property and is included in the accompanying statements of operations. For additional discussion, please refer to Note 3 – Divestitures and Assets Held for Sale.

Materials Inventory

The Company’s materials inventory is primarily comprised of tubular goods to be used in future drilling operations. Materials inventory is valued at the lower of cost or market and totaled $16.5 million and $22.5 million at December 31, 2011, and 2010, respectively. There were no materials inventory write downs for the years ended December 31, 2011, and 2010. The Company incurred $14.2 million of net materials inventory write-downs for year the ended December 31, 2009, as a result of a decrease in the market value of tubular goods.

Assets Held for Sale

Any properties held for sale as of the date of presentation of the balance sheet have been classified as assets held for sale and are separately presented on the accompanying balance sheets at the lower of net book value or fair value less the cost to sell. The asset retirement obligation liabilities related to such properties have been reclassified to asset retirement obligations associated with oil and gas properties held for sale in the accompanying balance sheets. For additional discussion on assets held for sale, please refer to Note 3 – Divestitures and Assets Held for Sale.

Other Property and Equipment

Other property and equipment such as facilities, office furniture and equipment, buildings, and computer hardware and software are recorded at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repair costs are expensed when incurred. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets which range from three to thirty years. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Intangible Assets

As of December 31, 2011, and 2010, the Company has $7.1 million and $4.4 million, respectively, of intangible assets, which is included as other noncurrent assets in the accompanying balance sheets. These assets arose from acquired indefinite life water rights. All indefinite life intangible assets are evaluated for impairment at

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least annually and if such indicators arise.

Cash Settlement Balancing

The Company uses the sales method of accounting for gas revenue whereby sales revenue is recognized on all gas sold to purchasers, regardless of whether the sales are proportionate to the Company's ownership in the property. An asset or liability is recognized to the extent that there is an imbalance in excess of the remaining gas reserves on the underlying properties. As of December 31, 2011, and 2010, the Company's has recorded a receivable of $1.9 million and $1.5 million, respectively, and a liability of $1.1 million and $934,000, respectively, which is included as other noncurrent assets and other noncurrent liabilities in the accompanying balance sheets.

Derivative Financial Instruments

The Company seeks to manage or reduce commodity price risk on production by entering into derivative contracts. The Company seeks to minimize its basis risk and indexes its oil derivative contracts to NYMEX prices, its NGL derivative contracts to OPIS prices, and the majority of its gas derivative contracts to various regional index prices associated with pipelines in proximity to the Company's areas of gas production. For additional discussion on derivatives, please see Note 10 – Derivative Financial Instruments.

Net Profits Plan

The Company records the estimated fair value of expected future payments made under the Net Profits Plan as a noncurrent liability in the accompanying balance sheets. The underlying assumptions used in the calculation of the estimated liability include estimates of production, proved reserves, recurring and workover lease operating expense, transportation, production and ad valorem tax rates, present value discount factors, pricing assumptions, and overall market conditions. The estimates used in calculating the long-term liability are adjusted from period-to-period based on the most current information attributable to the underlying assumptions. Changes in the estimated liability of future payments associated with the Net Profits Plan are recorded as increases or decreases to expense in the current period as a separate line item in the accompanying statements of operations, as these changes are considered changes in estimates.

The distribution amounts due to participants and payable in each period under the Net Profits Plan as cash compensation related to periodic operations are recognized as compensation expense and are included within general and administrative expense and exploration expense in the accompanying statements of operations. The corresponding current liability is included in accounts payable and accrued expenses in the accompanying balance sheets. This treatment provides for a consistent matching of cash expense with net cash flows from the oil and gas properties in each respective pool of the Net Profits Plan. For additional discussion, please refer to the heading Net Profits Plan in Note 7 – Compensation Plans and Note 11 – Fair Value Measurements.

Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. For additional discussion, please refer to Note 9 – Asset Retirement Obligations.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, gas, and NGLs. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported separately as expenses and are included in oil and gas production expense in the accompanying statements of operations. Revenue is recorded in the month the Company’s production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, NYMEX, OPIS, and local spot market prices, quality and transportation differentials, and other factors as the basis for these estimates.

Major Customers

During 2011 and 2010, sales to Regency Gas Services LLC individually accounted for approximately 18 percent and 11 percent, respectively, of the Company's total oil, gas, and NGL production revenue. During 2009, sales to Teppco Crude Oil LLC individually accounted for 12 percent of the Company's total oil and gas production revenue.

Stock Based Compensation

At December 31, 2011, the Company had stock-based employee compensation plans that included Restricted Stock Units ("RSUs"), Performance Share Awards ("PSAs"), Performance Share Units ("PSUs"), stock awards, and stock options issued to employees and non-employee directors, as more fully described in Note 7 - Compensation Plans. PSUs are structurally the same as the previously granted PSAs (collectively known as "Performance Share Units" or "PSUs"). The Company records expense associated with the fair value of stock-based compensation in accordance with authoritative accounting guidance. The Company records compensation expense associated with the issuance of RSUs and PSUs based on the estimated fair value of these awards determined at the time of grant.

Income Taxes

The Company accounts for deferred income taxes whereby deferred tax assets and liabilities are recognized based on the tax effects of temporary differences between the carrying amount on the financial statements and the tax basis of assets and liabilities, as measured using current enacted tax rates. These differences will result in taxable income or deductions in future years when the reported amounts of the assets or liabilities are recorded or settled, respectively. The Company records deferred tax assets and associated valuation allowances, when appropriate, to reflect amounts more likely than not to be realized based upon Company analysis.

Earnings per Share

Basic net income or loss per common share is calculated by dividing net income or loss available to common stockholders by the basic weighted-average common shares outstanding for the respective period. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income or loss per common share is calculated by dividing adjusted net income or loss by the diluted weighted-average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options, unvested RSUs, contingent PSUs, and shares into which the 3.50% Senior Convertible Notes are convertible.

PSUs represent the right to receive, upon settlement of the PSUs after the completion of the three-year performance period, a number of shares of the Company’s common stock that may range from zero to two times the number of PSUs granted on the award date. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective reporting period, assuming that date was the end of the contingency period. For additional discussion on PSUs, please refer to Note 7 – Compensation Plans under the heading Performance Share Units Under the Equity Incentive Compensation Plan.

The Company’s 3.50% Senior Convertible Notes have a net-share settlement right giving the Company the option to irrevocably elect, by notice to the trustee under the indenture for the notes, to settle the Company's obligation, in the event that holders of the notes elect to convert all or a portion of their notes, by delivering cash in an amount equal to each $1,000 principal amount of notes surrendered for conversion and, if applicable, at the Company's option, shares of common stock or cash, or any combination of common stock and cash, for the amount of conversion value in excess of the principal amount. For accounting purposes, the treasury stock method is used to measure the potential dilutive impact of shares associated with this conversion feature. Shares of the Company's common stock traded at an average closing price exceeding the $54.42 conversion price for the twelve-month period ended December 31, 2011, making them dilutive for that period. The 3.50% Senior Convertible Notes were not dilutive for any reporting period prior to 2011 and therefore do not impact the diluted earnings per share calculation for the years ended December 31, 2010, and 2009.

The treasury stock method is used to measure the dilutive impact of in-the-money stock options, unvested RSUs, contingent PSUs, and 3.50% Senior Convertible Notes as calculated in the basic and dilutive earnings per share table below. When there is a loss from continuing operations, as was the case for the year ended December 31, 2009, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of earnings per share. The following table details the weighted-average dilutive and anti-dilutive securities related to stock options, RSUs, PSUs, and the 3.50% Senior Convertible Notes for the years presented:

	For the Years Ended December 31,		
	2011	2010	2009
Dilutive	3,808,589	1,720,149	—
Anti-dilutive	—	—	1,152,127

The following table sets forth the calculations of basic and diluted earnings per share:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands, except per share amounts)		
Net income (loss)	$215,416	$196,837	$(99,370)
Basic weighted-average common shares outstanding	63,755	62,969	62,457
Add: dilutive effect of stock options, unvested RSUs, and contingent PSUs	2,592	1,720	—
Add: dilutive effect of 3.50% Senior Convertible Notes	1,217	—	—
Diluted weighted-average common shares outstanding	67,564	64,689	62,457
Basic net income (loss) per common share	$3.38	$3.13	$(1.59)
Diluted net income (loss) per common share	$3.19	$3.04	$(1.59)

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of stockholders' equity instead of net income (loss). Comprehensive income (loss) is presented net of income taxes in the accompanying consolidated statements of stockholders' equity and comprehensive income (loss).

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The changes in the balances of components comprising other comprehensive income (loss) are presented in the following table:

	Change in Derivative Instrument Fair Value (in thousands)	Derivative Reclassification to Earnings	Pension Liability Adjustments
For the year ended December 31, 2009			
Before tax income (loss)	$(57,613)	$(108,071)	$119
Tax benefit (expense)	21,636	40,727	(45)
Income (loss), net of tax	$(35,977)	$(67,344)	$74
For the year ended December 31, 2010			
Before tax income (loss)	$26,904	$10,608	$(1,570)
Tax benefit (expense)	(10,093)	(3,967)	590
Income (loss), net of tax	$16,811	$6,641	$(980)
For the year ended December 31, 2011			
Before tax income (loss)	$—	$20,707	$(2,779)
Tax benefit (expense)	—	(7,710)	984
Income (loss), net of tax	$—	$12,997	$(1,795)

Fair Value of Financial Instruments

The Company's financial instruments including cash and cash equivalents, accounts receivable, and accounts payable are carried at cost, which approximates fair value due to the short-term maturity of these instruments. The recorded value of the Company's credit facility approximates its fair value as it bears interest at a floating rate that approximates a current market rate. The Company had no outstanding loans under its credit facility as of December 31, 2011. The Company had $48.0 million in borrowings outstanding under its credit facility as of December 31, 2010. The Company's 3.50% Senior Convertible Notes, 6.625% Senior Notes, and 6.50% Senior Notes are recorded at cost, and the fair values are disclosed in Note 11 - Fair Value Instruments. The Company has derivative financial instruments that are recorded at fair value. Considerable judgment is required to develop estimates of fair value. The estimates provided are not necessarily indicative of the amounts the Company would realize upon the sale or refinancing of such instruments.

Industry Segment and Geographic Information

The Company operates exclusively in the exploration and production segment, and all of the Company's operations are conducted entirely in the United States in North America. The Company reports as a single industry segment. The Company's gas marketing function provides mostly internal services and acts as the first purchaser of natural gas and natural gas liquids produced by the Company in certain cases. The Company considers its marketing function as ancillary to its oil and gas producing activities. The amount of income these operations generate from marketing gas produced by third parties is not material to the Company's financial position, and segmentation of such activity would not provide a better understanding of the Company's performance. However, gross revenue and expense related to marketing activities for gas produced by third parties are presented in the marketed gas system revenue and marketed gas system expense line items in the accompanying statements of operations.

Off-Balance Sheet Arrangements

The Company has not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities ("SPEs"), which would have been established for the purpose of facilitating off-balance sheet arrangements or other

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contractually narrow or limited purposes. The Company has not been involved in any unconsolidated SPE transactions.

The Company evaluates its transactions to determine if any variable interest entities exist. If it is determined that SM Energy is the primary beneficiary of a variable interest entity, that entity is consolidated into SM Energy.

Recently Issued Accounting Standards

In May 2011, the FASB issued new fair value measurement authoritative accounting guidance clarifying the application of fair value measurement and disclosure requirements and changes particular principles or requirements for measuring fair value. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this authoritative accounting guidance and assessing the impact, if any, it may have on the Company’s fair value disclosures beginning in the first quarter of 2012.

In June 2011, the FASB issued new authoritative accounting guidance that states an entity that reports items of other comprehensive income has the option to present the components of net income and comprehensive income in either one continuous financial statement, or two consecutive financial statements, including reclassification adjustments. In December 2011, the FASB issued new authoritative accounting guidance which effectively deferred the requirement to present the reclassification adjustments on the face of the financial statements. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2011. The Company will apply this new athoritative accounting guidance in the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2012.

In December 2011, the FASB issued new authoritative accounting guidance related to balance sheet offsetting of certain assets and liabilities and assets and liabilities subject to master netting arrangements. The Company currently is not affected by this new authoritative accounting guidance; however, it will continue to evaluate the provisions of this authoritative accounting guidance and assess the impact, if any, it may have on the Company’s financial statements.

Note 2 – Accounts Receivable and Accounts Payable and Accrued Expenses

Accounts receivable are comprised of the following:

	As of December 31,	
	2011	2010
	(in thousands)	
Accrued oil, gas, and NGL sales	$149,384	$108,393
Due from joint interest owners	30,784	50,018
State severance tax refunds	14,979	2,114
Other	15,221	2,665
Total accounts receivable	$210,368	$163,190

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Accounts payable and accrued expenses are comprised of the following:

	As of December 31,	
	2011	2010
	(in thousands)	
Accrued drilling costs	$189,749	$241,298
Revenue and severance tax payable	61,613	37,066
Accrued lease operating expense	25,197	17,643
Joint owner advances	79,138	24,698
Accrued compensation	43,056	45,235
ARO liability	7,462	11,679
Accrued interest payable	14,646	2,582
Other	36,138	37,453
Total accounts payable and accrued expenses	$456,999	$417,654

Note 3 – Divestitures and Assets Held for Sale

Eagle Ford Shale Divestiture

In August 2011, the Company divested of certain operated Eagle Ford shale assets located in its South Texas & Gulf Coast region. This divestiture was comprised of the Company's entire operated acreage in LaSalle County, Texas, as well as an immaterial adjacent block of its operated acreage in Dimmit County, Texas. Total divestiture proceeds were $230.8 million. The estimated gain on this divestiture was $194.6 million. The final divestiture proceeds are subject to normal post-closing adjustments and are expected to be finalized during the first quarter of 2012.

Mid-Continent Divestiture

In June 2011, the Company divested of certain non-strategic assets located in its Mid-Continent region. Total divestiture proceeds were $35.8 million. The estimated gain on this divestiture was $28.5 million. The final divestiture proceeds are subject to normal post-closing adjustments and are expected to be finalized during the first quarter of 2012.

Rocky Mountain Divestiture

In January 2011, the Company divested of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $45.5 million. The final gain on this divestiture was $27.2 million.

Permian Divestiture

In December 2010, the Company completed the divestiture of certain non-strategic assets located in its Permian region. Total divestiture proceeds were $54.7 million. The final gain on this divestiture was $18.4 million.

Legacy Divestiture

In February 2010, the Company completed the divestiture of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $125.3 million. The final gain on this divestiture was $66.7 million. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code").

Sequel Divestiture

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In March 2010, the Company completed the divestiture of certain non-strategic assets located in its Rocky Mountain region. Total divestiture proceeds were $129.1 million. The final gain on this divestiture was $53.1 million. A portion of the transaction was structured to qualify as a like-kind exchange under Section 1031 of the Internal Revenue Code.

Assets Held for Sale

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to identify and expense any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale for which fair value is determined to be less than the carrying value of the assets.

In July 2011, the Company entered into agreements with Endeavour to divest of our Marcellus shale assets and related pipeline facilities located in Pennsylvania for $80.0 million net to the Company's interest. Subsequently, Endeavour failed to consummate the transaction after giving notice of its intent to terminate the agreement. The Company has disputed Endeavour's right to take these actions and is currently pursuing legal remedies including specific performance or damages from Endeavour. Due to the uncertainty surrounding the transaction, it was determined that these assets do not continue to meet the specific criteria required for presentation as assets held for sale. As a result the Company has reclassified these assets previously classified as held for sale to assets held and used. The Company measured the assets at the lower of the assets carrying amount before the assets were classified as held for sale, adjusted for any depreciation and depletion expense that would have been recognized had the assets been continuously classified as held and used, or the assets fair value at the subsequent date that the assets no longer met the criteria for assets held for sale. As a result of this measurement, the Company recognized $14.7 million of DD&A expense and a $27.5 million write-down to proved and unproved oil and gas properties. This write-down is included in gain on divestiture activity in the accompanying statements of operations.

The Company determined that none of the divestitures addressed above qualified for discontinued operations accounting under financial statement presentation authoritative accounting guidance.

Note 4 – Income Taxes

The provision for income taxes consists of the following:

	For the Years Ended December 31,					
	2011		2010		2009	
	(in thousands)					
Current portion of income tax (expense) benefit						
Federal	$1,757		$(2,903	)	$21,926	
State	(1,553	)	(639	)	(1,567	)
Deferred portion of income tax (expense) benefit	(123,789	)	(114,517	)	39,735	
Total income tax (expense) benefit	$(123,585	)	$(118,059	)	$60,094	
Effective tax rate	36.5	%	37.5	%	37.7	%

As a result of the exercise of stock options, the Company reduced its income tax payable in 2010. The excess income tax benefit to the Company associated with stock awards was $854,000 in 2010. There was no excess income tax benefit associated with stock awards in 2011 or 2009.

The components of the net deferred income tax liabilities are as follows:

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	As of December 31,	
	2011	2010
	(in thousands)	
Deferred tax liabilities:		
Oil and gas properties	$639,485	$528,652
Unrealized derivative asset	13,274	—
Interest on 3.50% Senior Convertible Notes	2,256	2,219
Other	1,873	2,723
Total deferred tax liabilities	656,888	533,594
Deferred tax assets:		
Net Profits Plan liability	40,148	50,922
Stock compensation	17,728	13,143
Federal and state tax net operating loss carryovers	23,651	10,772
Federal and state tax credit carryovers	4,301	—
Unrealized derivative liability	—	6,929
Other long-term liabilities	10,810	19,740
Total deferred tax assets	96,638	101,506
Valuation allowance	(3,791)	(2,164)
Net deferred tax assets	92,847	99,342
Total net deferred tax liabilities	564,041	434,252
Less: current deferred income tax liabilities	(3,307)	(2,710)
Add: current deferred income tax assets	7,529	11,593
Non-current net deferred tax liabilities	$568,263	$443,135
Current federal income tax refundable	$5,581	$8,482
Current state income tax payable	$774	$294

At December 31, 2011, the Company had estimated a federal net operating loss carryforward of $77.2 million, which includes $42.9 million unrecognized excess income tax benefit associated with stock awards. The federal net operating loss carryforward expires in 2031. The Company had estimated state net operating loss carryforwards of $287.8 million expiring between 2012 and 2031. The Company has federal research and development credit carryforwards of $4.0 million expiring in 2031 and other state tax credits of $352,000 which expire between 2012 and 2021. The Company’s valuation allowance relates to charitable contribution carryfowards, state net operating loss carryforwards, state tax credits, and state and federal income tax benefit amounts, which the Company anticipates will expire before they can be utilized. Permanent items included in the calculation of income tax for certain states are anticipated to impact the Company’s ability to deduct operating losses and realize federal income tax deduction benefits in those states, and the Company adjusts its valuation allowances accordingly. The change in the valuation allowance from 2010 to 2011, indicated below, primarily reflects a change in the Company’s position regarding anticipated utilization of charitable contribution carryforward amounts.

Federal income tax expense differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes primarily due to the effect of state income taxes, research and development credits, percentage depletion, the estimated effect of the domestic production activities deduction, changes in valuation allowances, and other permanent differences, as follows:

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	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Federal statutory tax (expense) benefit	$(118,652)	$(110,214)	$55,812
(Increase) decrease in tax resulting from:			
State tax (expense) benefit (net of federal benefit)	(6,458)	(7,750)	5,141
Research and development credit	4,516	—	—
Change in valuation allowance	(1,627)	1,039	(56)
Statutory depletion	341	266	189
Other	(1,705)	(1,400)	(992)
Income tax (expense) benefit	$(123,585)	$(118,059)	$60,094

Acquisitions, divestitures, drilling activity, and basis differentials impacting the prices received for oil, gas, and NGLs affect apportionment of taxable income to the states where the Company owns oil and gas properties. As its apportionment factors change, the Company’s blended state income tax rate changes. This change, when applied to the Company’s total temporary differences, impacts the total income tax reported in the current year and is reflected in state taxes in the table above. Items affecting state apportionment factors are evaluated at the beginning of each year after completion of the prior year income tax return and when significant acquisition, divestiture or change in drilling activity occurs during the year.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before 2007. In the third quarter of 2011, the Company completed a research and development credit study and filed an amended 2007 federal return to claim a credit for that year. In the first quarter of 2011, the Company received a $5.5 million refund from its 2006 tax year as a result of a net operating loss carryback claim from the 2008 tax year. In the fourth quarter of 2010, the Internal Revenue Service initiated an audit of the Company for the 2009 tax year. The audit was concluded in the second quarter of 2011 with a nominal decrease to the Company's total 2005 refund claim, which was $25.0 million. A quick refund claim of $22.9 million from 2005 was received in the third quarter of 2010. The balance was received in the fourth quarter of 2011.

The Company complies with uncertainty provisions of the income tax authoritative accounting guidance. The entire amount of unrecognized tax benefit reported by the Company would affect its effective tax rate if recognized. Interest expense in the accompanying statements of operations includes a negligible amount associated with income tax. In 2011, the Company also recorded a negligible amount of penalty expense associated with income taxes as a general and administrative expense. There were no penalties for 2010 and 2009.

The total amount recorded for unrecognized tax benefits is presented below:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Beginning balance	$807	$884	$994
Additions based on tax positions related to current year	1,172	—	—
Additions for tax positions of prior years	183	244	231
Reductions for lapse of statute of limitations	(201)	(321)	(341)
Ending balance	$1,961	$807	$884

Note 5 – Long-term Debt

Revolving Credit Facility

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The Company executed a Fourth Amended and Restated Credit Agreement on May 27, 2011. This amended revolving credit facility replaced the Company's previous facility. The Company incurred $8.7 million of deferred financing costs in association with the amended credit facility. Borrowings under the facility are secured by substantially all of the Company's proved oil and gas properties. The credit facility has a maximum loan amount of $2.5 billion, with current aggregate lender commitments of $1.0 billion, and a maturity date of May 27, 2016. On November 8, 2011, the Company's borrowing base under the credit facility was automatically reduced by approximately 25% of the aggregate principal amount of the newly-issued 6.50% Senior Notes, to $1.3 billion, down from $1.4 billion. The borrowing base is subject to regular semi-annual redeterminations by the Company's lenders. The borrowing base redetermination process considers the value of the Company's oil and gas properties.

The Company must comply with certain financial and non-financial covenants under the terms of its credit facility agreement, including the limitation of the Company's dividends to no more than $50.0 million per year. The Company was in compliance with all financial covenants under the credit facility as of December 31, 2011.

Interest and commitment fees are accrued based on the borrowing base utilization grid below. Eurodollar loans accrue interest at the London Interbank Offered Rate plus the applicable margin from the utilization table below, and Alternate Base Rate ("ABR") and swingline loans accrue interest at Prime plus the applicable margin from the utilization table below. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the accompanying statements of operations.

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	<25%		≥25% <50%		≥50% <75%		≥75% <90%		≥90%	
Eurodollar Loans	1.500	%	1.750	%	2.000	%	2.250	%	2.500	%
ABR Loans or Swingline Loans	0.500	%	0.750	%	1.000	%	1.250	%	1.500	%
Commitment Fee Rate	0.375	%	0.375	%	0.500	%	0.500	%	0.500	%

The Company had no outstanding borrowings under its credit facility as of December 31, 2011. The Company had $48.0 million in outstanding loans under its revolving credit agreement at December 31, 2010. The Company had $999.4 million of available borrowing capacity under its current credit facility as of February 16, 2012, and December 31, 2011, and $629.5 million of available borrowing capacity under its previous credit facility as of December 31, 2010. The Company had two letters of credit outstanding totaling $608,000 at February 16, 2012, and December 31, 2011, and one letter of credit outstanding in the amount of $483,000 as of December 31, 2010. Outstanding letters of credit reduce the amount available under the commitment amount on a dollar-for-dollar basis.

6.50% Senior Notes Due 2021

On November 8, 2011, the Company issued $350.0 million in aggregate principal amount of 6.50% Senior Notes. The 6.50% Senior Notes were issued at par and mature on November 15, 2021. The Company received net proceeds of $343.1 million after deducting fees of $6.9 million, which will be amortized as deferred financing costs over the life of the 6.50% Senior Notes. The net proceeds have been and will be used for general corporate purposes, which may include funding the put, redemption or conversion of all or a portion of the 3.50% Senior Convertible Notes.

Prior to November 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 6.50% Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.5% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 6.50% Senior Notes, in whole or in part, at any time prior to November 15, 2016, at a redemption price equal to 100% of the principal amount, plus a specified make whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 6.50% Senior Notes on or after

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November 15, 2016, at the prices set forth below, during the twelve-month period beginning on November 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2016	103.250	%
2017	102.167	%
2018	101.083	%
2019 and thereafter	100.000	%

The 6.50% Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 6.50% Senior Notes. The Company is subject to certain covenants under the indenture governing the 6.50% Senior Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments, including dividends; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all covenants under its 6.50% Senior Notes as of December 31, 2011.

Additionally, on November 8, 2011, the Company entered into a registration rights agreement that provides holders of the 6.50% Senior Notes certain registration rights for the 6.50% Senior Notes under the Securities Act of 1933, as amended (the "Securities Act"). On January 19, 2012, the Company filed a registration statement relating to an offer to exchange the outstanding 6.50% Senior Notes for substantially identical notes registered under the Securities Act. The registration statement related to the exchange offer was declared effective by the Securities and Exchange Commission on January 31, 2012. The offer to exchange $350.0 million of its 6.50% Senior Notes, which have been registered under the Securities Act, for $350.0 million of its outstanding 6.50% Senior Notes has not yet closed. Under certain circumstances, in lieu of a registered exchange offer, the Company has agreed to file a shelf registration statement with respect to the 6.50% Senior Notes. If the exchange offer is not completed on or before November 8, 2012, or the shelf registration statement, if required, is not declared effective within the time periods specified in the registration rights agreement, then the Company has agreed to pay additional interest with respect to the 6.50% Senior Notes in an amount not to exceed one percent of the principal amount of the 6.50% Senior Notes until the exchange offer is completed or the shelf registration statement is declared effective.

6.625% Senior Notes Due 2019

On February 7, 2011, the Company issued $350.0 million in aggregate principal amount of 6.625% Senior Notes. The 6.625% Senior Notes were issued at par and mature on February 15, 2019. The Company received net proceeds of $341.1 million after deducting fees of $8.9 million, which will be amortized as deferred financing costs over the life of the 6.625% Senior Notes. The net proceeds were used to repay all borrowings under the Company's previous credit facility, fund the Company's ongoing capital expenditure program, and general corporate purposes.

Prior to February 15, 2014, the Company may redeem up to 35 percent of the aggregate principal amount of the 6.625% Senior Notes with the net cash proceeds of one or more equity offerings at a redemption price of 106.625% of the principal amount thereof, plus accrued and unpaid interest. The Company may also redeem the 6.625% Senior Notes, in whole or in part, at any time prior to February 15, 2015, at a redemption price equal to 100% of the principal amount, plus a specified make whole premium and accrued and unpaid interest.

The Company may also redeem all or, from time to time, a portion of the 6.625% Senior Notes on or after February 15, 2015, at the prices set forth below, during the twelve-month period beginning on February 15 of the applicable year, expressed as a percentage of the principal amount redeemed, plus accrued and unpaid interest:

2015	103.313	%
2016	101.656	%

2017 and thereafter	100.000	%

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The 6.625% Senior Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt. There are no subsidiary guarantors of the 6.625% Senior Notes. The Company is subject to certain covenants under the indenture governing the 6.625% Senior Notes that limit incurring additional indebtedness, issuing preferred stock, and making restricted payments, including dividends; provided, however, the first $6.5 million of dividends paid each year are not restricted by this covenant. The Company was in compliance with all financial covenants under its 6.625% Senior Notes as of December 31, 2011.

Additionally, on February 7, 2011, the Company entered into a registration rights agreement that provides holders of the 6.625% Senior Notes certain registration rights for the 6.625% Senior Notes under the Securities Act. On January 11, 2012, the offer to exchange $350.0 million of its 6.625% Senior Notes, which have been registered under the Securities Act, for $350.0 million of its outstanding 6.625% Senior Notes was completed.

3.50% Senior Convertible Notes Due 2027

On April 4, 2007, the Company issued $287.5 million in aggregate principal amount of 3.50% Senior Convertible Notes. The 3.50% Senior Convertible Notes mature on April 1, 2027, unless converted prior to maturity, redeemed, or purchased by the Company. The 3.50% Senior Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company's existing and any future unsecured senior debt and are senior in right of payment to any future subordinated debt.

Holders may convert their notes based on a conversion rate of 18.3757 shares of the Company's common stock per $1,000 principal amount of the 3.50% Senior Convertible Notes (which is equal to an initial conversion price of $54.42 per share), subject to adjustment and contingent upon and only under the following circumstances: (1) if the closing price of the Company's common stock reaches specified thresholds or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company's common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to but excluding the maturity date.

Upon conversion of the 3.50% Senior Convertible Notes, holders will receive cash or common stock or any combination thereof as elected by the Company. At any time prior to the maturity date of the notes, the Company has the option to unilaterally and irrevocably elect to net share settle its obligations upon conversion of the notes in cash and, if applicable, shares of common stock. If the Company makes this election, then the Company will pay the following to holders for each $1,000 principal amount of notes converted in lieu of shares of common stock: (1) an amount in cash equal to the lesser of (i) $1,000 or (ii) the conversion value determined in the manner set forth in the indenture for the 3.50% Senior Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion.

If a holder of 3.50% Senior Convertible Notes elects to convert its notes in connection with certain events that constitute a change of control before April 1, 2012, the Company will pay, to the extent described in the related indenture, a make-whole premium by increasing the conversion rate applicable to the 3.50% Senior Convertible Notes. In addition, the Company will pay contingent interest in cash, commencing with any six-month period beginning on or after April 1, 2012. Contingent interest will be payable if the average trading price of a note for the five trading days ending on the third trading day immediately preceding the first day of the relevant six-month period equals 120 percent or more of the principal amount of the 3.50% Senior Convertible Notes.

Holders of the 3.50% Senior Convertible Notes may elect to surrender all or a portion of their 3.50% Senior Convertible Notes for conversion under certain circumstances, including during a calendar quarter if the closing price of the Company's common stock was more than 130 percent of the conversion price of $54.42 per share for at least 20 trading days in the 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter. If holders elect to convert all or a portion of the 3.50% Senior Convertible Notes during a calendar quarter in which they are eligible to do so, they will receive cash, shares of the Company's common stock,

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or any combination thereof as may be elected by the Company under the indenture for the 3.50% Senior Convertible Notes. The Company's common stock exceeded the conversion trigger price of $70.75 at various times during 2011. However, none of the holders opted to convert their 3.50% Senior Convertible Notes during the year. The Company's common stock exceeded the conversion trigger price for the quarter ended December 31, 2011. Therefore, the holders of the 3.50% Senior Convertible Notes have the right to convert all or a portion of their notes during the first quarter of 2012.

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Senior Convertible Notes at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, up to but excluding the applicable redemption date. Holders of the 3.50% Senior Convertible Notes may require the Company to purchase all or a portion of their notes on each of April 1, 2012, April 1, 2017, and April 1, 2022, at a purchase price equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date. On April 1, 2012, the Company may pay the purchase price in cash, in shares of common stock, or in any combination of cash and common stock. On April 1, 2017, and April 1, 2022, the Company must pay the purchase price in cash.

Capitalized Interest

Capitalized interest costs for the Company for the years ended December 31, 2011, 2010, and 2009, were $10.8 million, $4.3 million, and $1.9 million, respectively.

Note 6 – Commitments and Contingencies

Commitments

The Company has entered into various agreements, which include drilling rig leasing contracts of $143.0 million, gathering, transportation, and processing through-put commitments of $893.6 million, office space leases, including maintenance, of $37.4 million, hydraulic fracturing contracts of $19.2 million, and other miscellaneous contracts and leases of $5.7 million. The annual minimum payments for the next five years and total minimum lease payments thereafter are presented below:

Years Ending December 31,	(in thousands)
2012	$131,021
2013	99,633
2014	108,629
2015	97,401
2016	100,635
Thereafter	561,642
Total	$1,098,961

The Company has gathering, processing, and transportation through-put commitments with various parties that require delivery of a fixed determinable quantity of product. The aggregate minimum commitment to deliver is 1,766 Bcf of natural gas and 9 MMBbls of oil. These contracts expire at various dates through 2023 and the total amount of the commitment is $893.6 million. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume commitments. The Company expects to fulfill the delivery commitments.

The Company leases office space under various operating leases with terms extending as far as September 30, 2022. Rent expense for 2011, 2010, and 2009 was $3.7 million, $2.7 million, and $2.3 million, respectively. Rent expense for 2009 is net of sub lease rent of $185,000; there is no sublease rent for 2010 or 2011. The Company also leases office equipment under various operating leases.

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In addition to the amounts in the above table, the Company entered into a three-year capital project commencing 2011 for the development of infrastructure in the Company's non-operated Eagle Ford shale play. Pursuant to the terms of the agreement for the construction, ownership and operation of the assets, the Company is required to pay its portion of the costs. Based on current estimates, the Company does not expect its costs to exceed $75 million over the duration of the agreement.

Contingencies

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such pending litigation and claims will not have a material effect on the results of operations, the financial position, or cash flows of the Company.

The Company is currently a defendant in litigation where the plaintiffs claim an aggregate overriding royalty interest of 7.46875 percent in production from approximately 22,000 of the Company’s net acres in the Eagle Ford shale play in South Texas. The plaintiffs seek to quiet title to their claimed overriding royalty interest and seek the recovery of unpaid overriding royalty interest proceeds allegedly due. The Texas District Court issued an order granting plaintiffs’ motion for summary judgment, but the Company believes that the summary judgment order is incorrect under the governing agreements and applicable law, and the Company has filed its appeal and will continue to contest the claim. The court entered judgment against all defendants awarding the plaintiffs damages of $5.1 million. If the plaintiffs were to ultimately prevail, the overriding royalty interest would reduce the Company’s net revenue interest in the affected acreage. The Company does not currently believe that an unfavorable ultimate outcome is probable, nor that if the plaintiffs prevail there would be a material effect on the financial position of the Company. Based on the Company’s current view of the facts and circumstances of the case, no accrual has been made for any loss.

Note 7 – Compensation Plans

Cash Bonus Plan

The Company has a cash bonus plan based on a performance measurement framework whereby selected eligible employee participants may be awarded an annual cash bonus. The plan document provides that no participant may receive an annual bonus under the plan of more than 200 percent of his or her base salary. As the plan is currently administered, any awards under the plan are based on Company and regional performance, and are then further refined by individual performance. The Company accrues cash bonus expense based upon the Company’s current year’s performance. Included in general and administrative and exploration expense in the accompanying statements of operations are $23.9 million, $21.6 million, and $7.8 million of cash bonus expense related to the specific performance year for the years ended December 31, 2011, 2010, and 2009, respectively.

Equity Incentive Compensation Plan

There are several components to the equity compensation plan, referred to as the Equity Plan throughout this report, that are described in this section. Various types of equity awards have been granted by the Company in different periods.

As of December 31, 2011, 2.7 million shares of common stock remained available for grant under the Equity Plan. The issuance of a direct share benefit such as a share of common stock, a restricted share, a RSU, or a PSU counts as 1.43 shares against the number of shares available to be granted under the Equity Plan. Each PSU has the potential to count as 2.86 shares against the number of shares available to be granted under the Equity Plan based on the final multiplier. Stock option grants count as one share for each instrument granted against the number of shares available to be granted under the Equity Plan. Stock options were issued out of the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan.

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Performance Share Units Under the Equity Incentive Compensation Plan

PSUs are the primary form of long-term equity incentive compensation for the Company. The PSU factor is based on the Company's performance after completion of a three-year performance period. The performance criteria for the PSUs are based on a combination of the Company's annualized Total Shareholder Return ("TSR") for the performance period and the relative measure of the Company's TSR compared with the annualized TSR of an index comprised of certain peer companies for the performance period. PSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

The fair value of PSUs was measured at the grant date using a stochastic process method using the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the three-year performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility, dividend yield, and risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with a three year vesting period, as well as the volatilities and dividend yields for each of the Company's peers.

Total expense recorded for PSUs was $19.7 million, $17.7 million, and $9.3 million for the years ended December 31, 2011, 2010, and 2009, respectively. As of December 31, 2011, there was $26.4 million of total unrecognized expense related to PSUs, which is being amortized through 2014.

A summary of the status and activity of PSUs for the years ended December 31, 2011, 2010, and 2009 is presented in the following table:

	2011		2010		2009	
	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value	PSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year(1)	1,110,666	$ 39.48	1,069,090	$ 32.52	464,333	$ 26.48
Granted(1)	266,282	$ 91.45	387,651	$ 52.35	725,092	$ 35.59
Vested(1)	(364,172)	$ 35.74	(210,801)	$ 31.18	(76,781)	$ 27.20
Forfeited(1)	(126,882)	$ 33.32	(135,274)	$ 34.28	(43,554)	$ 28.62
Non-vested at end of year(1)	885,894	$ 57.52	1,110,666	$ 39.48	1,069,090	$ 32.52

(1) The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending on the ending three-year performance multiplier, which ranges from zero to two.

The total fair value of PSUs that vested during the years ended December 31, 2011, 2010, and 2009 was $13.0 million, $6.6 million, and $1.8 million, respectively.

The Company granted PSUs in 2011, 2010, and 2009 as part of its regular annual long-term equity compensation process. The fair value of these grants was $24.3 million, $20.3 million, and $25.8 million for the 2011, 2010, and 2009 grants, respectively. The PSUs vest 1/7th, 2/7ths, and 4/7ths on the first three anniversary dates of their issuances.

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During 2011, the Company settled 305,423 PSUs that relate to awards granted in 2008 through the issuance of shares of the Company's common stock in accordance with the terms of the PSU awards. As a result, the Company issued a net of 206,468 shares of common stock associated with these grants. The remaining 98,955 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon delivery of the shares underlying those PSUs.

Restricted Stock Units Under the Equity Incentive Compensation Plan

The Company grants RSUs as a part of its equity incentive compensation program to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards are determined by the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company’s common stock to be delivered upon settlement of the award at the end of a specified period. RSUs are recognized as general and administrative and exploration expense over the vesting period of the award.

The total expense associated with RSUs for the years ended December 31, 2011, 2010, and 2009, was $5.3 million, $7.7 million, and $7.9 million, respectively. As of December 31, 2011, there was $7.5 million of total unrecognized expense related to unvested RSU awards, which is being amortized through 2014. The Company records compensation expense associated with the issuance of RSUs based on the estimated fair value of the awards. The fair value of an RSU is equal to the closing price of the Company's common stock on the day of grant.

A summary of the status and activity of non-vested RSUs for the years ended December 31, 2011, 2010, and 2009, is presented below:

	2011		2010		2009	
	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value	RSUs	Weighted-Average Grant-Date Fair Value
Non-vested at beginning of year	333,359	$31.16	407,123	$34.67	402,297	$48.24
Granted	98,952	$72.69	128,865	$40.31	241,745	$23.87
Vested	(105,820)	$30.61	(160,398)	$46.30	(211,092)	$46.26
Forfeited	(17,614)	$36.80	(42,231)	$35.43	(25,827)	$50.35
Non-vested at end of year	308,877	$44.33	333,359	$31.16	407,123	$34.67

The total fair value of RSUs that vested during the years ended December 31, 2011, 2010, and 2009, was $3.2 million, $7.4 million, and $9.8 million, respectively.

The Company issued 98,952 RSUs in 2011, 128,865 RSUs in 2010, and 241,745 RSUs in 2009 as part of its long-term equity compensation process. The fair value associated with these issuances was $7.2 million, $5.2 million, and $5.8 million, respectively. These RSUs vest 1/7th, 2/7^{ths}, and 4/7^{ths} on the first three anniversary dates of their issuances.

During the years ended December 31, 2011, 2010, and 2009, the Company settled 105,820, 160,381, and 215,700 RSUs, respectively. The Company and the majority of grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued net shares of common stock of 72,305, 113,103, and 156,252 for 2011, 2010, and 2009, respectively. The remaining 33,515, 47,278, and 59,448 shares were withheld to satisfy income and payroll tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs for 2011, 2010, and 2009, respectively.

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Stock Option Grants Under the Equity Incentive Compensation Plan

The Company has previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and the St. Mary Land & Exploration Company Incentive Stock Option Plan. The last issuance of stock options occurred on December 31, 2004. Stock options to purchase shares of the Company's common stock had been granted to eligible employees and members of the Board of Directors. All options granted under the option plans have been granted at exercise prices equal to the respective closing market price of the Company's underlying common stock on the grant dates. All stock options granted under the option plans are exercisable for a period of up to ten years from the date of grant. As of December 31, 2011, 2010, and 2009, there was no unrecognized compensation expense related to stock option awards.

A summary of activity associated with the Company's Stock Option Plans during the last three years is presented in the following table:

	Shares		Weighted - Average Exercise Price	Aggregate Intrinsic Value
For the year ended December 31, 2009				
Outstanding, start of year	1,509,710		$12.69	
Exercised	(189,740	)	$8.40	4,625,148
Forfeited	(45,050	)	$13.38	
Outstanding, end of year	1,274,920		$13.31	$26,684,106
Vested and exercisable at end of year	1,274,920		$13.31	$26,684,106
For the year ended December 31, 2010				
Outstanding, start of year	1,274,920		$13.31	
Exercised	(346,377	)	$13.77	11,281,865
Forfeited	(7,778	)	$16.66	
Outstanding, end of year	920,765		$13.11	$42,192,057
Vested and exercisable at end of year	920,765		$13.11	$42,192,057
For the year ended December 31, 2011				
Outstanding, start of year	920,765		$13.11	
Exercised	(412,551	)	$12.19	24,359,240
Forfeited	—		$—	
Outstanding, end of year	508,214		$13.86	$30,109,110
Vested and exercisable at end of year	508,214		$13.86	$30,109,110

A summary of additional information related to options outstanding as of December 31, 2011, follows:

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Range of Exercise Prices			Options Outstanding and Exercisable Number Of Options Outstanding and Exercisable	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
$10.86	-	$11.95	35,964	0.66 years	$11.76
12.03	-	12.03	29,043	0.50 years	12.03
12.08	-	12.08	13,080	0.39 years	12.08
12.50	-	12.50	80,261	1.0 years	12.50
12.53	-	12.53	43,001	1.3 years	12.53
12.66	-	12.66	48,055	1.8 years	12.66
13.39	-	13.39	21,051	1.8 years	13.39
13.65	-	13.65	54,189	1.5 years	13.65
14.25	-	14.25	134,710	2.0 years	14.25
20.87	-	20.87	48,860	3.0 years	20.87
Total			508,214		

The fair value of options was measured at the date of grant using the Black-Scholes-Merton option-pricing model. Cash flows resulting from excess tax benefits are to be classified as part of cash flows from financing activities. Excess tax benefits are realized tax benefits from tax deductions for vested RSUs, settled PSUs, and exercised options in excess of the deferred tax asset attributable to stock compensation costs for such equity awards. The Company recorded $854,000 of excess tax benefits for the year ended December 31, 2010, as cash inflows from financing activities. The Company recorded no excess tax benefits for the years ended December 31, 2011, and December 31, 2009. Cash received from exercises under all share-based payment arrangements for the years ended December 31, 2011, 2010, and 2009, was $5.0 million, $4.8 million, and $1.6 million, respectively.

Director Shares

In 2011, 2010, and 2009, the Company issued 21,568, 24,258, and 50,094 shares, respectively, of the Company's common stock held as treasury shares to its non-employee directors pursuant to the Company’s Equity Plan. The Company recorded compensation expense related to these issuances of $1.2 million, $781,000, and $688,000 for the years ended December 31, 2011, 2010, and 2009, respectively.

Employee Stock Purchase Plan

Under the Company’s Employee Stock Purchase Plan ("ESPP"), eligible employees may purchase shares of the Company’s common stock through payroll deductions of up to 15 percent of eligible compensation, without accruing in excess of $25,000 in fair market value from purchases for each calendar year. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the purchase period. All shares issued under the ESPP as of December 31, 2011, have no minimum restriction period. The ESPP is intended to qualify under Section 423 of the IRC. The Company has 1.4 million shares available under the ESPP for issuance as of December 31, 2011. Shares issued under the ESPP totaled 41,358 in 2011, 52,948 in 2010, and 86,308 in 2009. Total proceeds to the Company for the issuance of these shares were $2.3 million in 2011, $1.7 million in 2010, and $1.5 million in 2009, respectively.

The fair value of ESPP shares was measured at the date of grant using the Black-Scholes-Merton option-pricing model. Expected volatility was calculated based on the Company's historical daily common stock price, and the risk-free interest rate is based on U.S. Treasury yield curve rates with maturities consistent with a six month vesting period.

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The fair value of ESPP shares issued during the periods reported were estimated using the following weighted-average assumptions:

	For the Years Ended December 31,					
	2011		2010		2009	
Risk free interest rate	0.2	%	0.2	%	0.3	%
Dividend yield	0.2	%	0.3	%	0.5	%
Volatility factor of the expected market price of the Company's common stock	36.3	%	46.3	%	95.1	%
Expected life (in years)	0.5		0.5		0.5	

The Company expensed $682,000, $550,000, and $848,000 for the years ended December 31, 2011, 2010, and 2009, respectively, based on the estimated fair value of grants.

401(k) Plan

The Company has a defined contribution pension plan (the "401(k) Plan") that is subject to the Employee Retirement Income Security Act of 1974. The 401(k) Plan allows eligible employees to contribute up to 60 percent of their base salaries up to the contribution limits established under the IRC. The Company matches each employee's contribution up to 6 percent of the employee's base salary and may make additional contributions at its discretion. The Company's contributions to the 401(k) Plan were $2.9 million, $2.5 million, and $2.5 million for the years ended December 31, 2011, 2010, and 2009, respectively. No discretionary contributions were made by the Company to the 401(k) Plan for any of these years.

Net Profits Plan

Under the Company's Net Profits Plan, all oil and gas wells that were completed or acquired during a year were designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year became entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. In December 2007, the Board of Directors discontinued the creation of new pools under the Net Profits Plan. As a result, the 2007 Net Profits Plan pool was the last pool established by the Company.

Cash payments made or accrued under the Net Profits Plan that have been recorded as either general and administrative expense or exploration expense are detailed in the table below:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
General and administrative expense	$19,326	$19,798	$18,399
Exploration expense	2,091	2,633	1,463
Total	$21,417	$22,431	$19,862

Additionally, the Company made or accrued cash payments under the Net Profits Plan of $6.3 million, $26.1 million, and $724,000 for the years ended December 31, 2011, 2010, and 2009, respectively, as a result of divestiture proceeds. The cash payments are accounted for as a reduction in the gain on divestiture activity in the accompanying statements of operations.

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The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate line item in the accompanying statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than results being realized through current period production. If the Company allocated the change in liability to these specific functional line items, based on the current allocation of actual distributions made by the Company, such expenses or benefits would predominately be allocated to general and administrative expense. The amount that would be allocated to exploration expense is minimal in comparison. Over time, less of the amount distributed relates to prospective exploration efforts as more of the amount distributed is to employees that have terminated employment and do not provide ongoing exploration support to the Company.

Note 8 – Pension Benefits

Pension Plans

The Company has a non-contributory defined benefit pension plan covering substantially all employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Nonqualified Pension Plan”).

The Company recognizes the funded status (i.e, the difference between the fair value of plan assets and the projected benefit obligation) of the Company’s pension plan in the accompanying balance sheets as either an asset or a liability and recognizes a corresponding adjustment to accumulated other comprehensive income, net of tax. The projected benefit obligation is the actuarial present value of the benefits earned to date by plan participants based on employee service and compensation including the effect of assumed future salary increases. The accumulated benefit obligation uses the same factors as the projected benefit obligation but excludes the effects of assumed future salary increases. The Company’s measurement date for plan assets and obligations is December 31.

Obligations and Funded Status for Both Pension Plans

	For the Years Ended December 31,	
	2011	2010
	(in thousands)	
Change in benefit obligations		
Projected benefit obligation at beginning of year	$23,867	$18,550
Service cost	3,800	3,392
Interest cost	1,184	1,120
Amendments	170	—
Actuarial loss	1,957	2,480
Benefits paid	(1,498)	(1,675)
Projected benefit obligation at end of year	$29,480	$23,867
Change in plan assets		
Fair value of plan assets at beginning of year	$10,332	$9,101
Actual return on plan assets	(176)	1,181
Employer contribution	5,260	1,725
Benefits paid	(1,476)	(1,675)
Fair value of plan assets at end of year	$13,940	$10,332
Funded status at end of year	$(15,540)	$(13,535)

The Company’s funded status for the Pension Plans for the years ended December 31, 2011 and 2010, is $15.5 million and $13.5 million, respectively, and is recognized in the accompanying balance sheets as a portion of other noncurrent liabilities. No plan assets of the Qualified Pension Plan were returned to the Company during the

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fiscal year ended December 31, 2011. There are no plan assets in the Nonqualified Pension Plan. The plan was amended to increase the vesting percent to 40% after attaining two years of service and increasing by 20% per year until fully vested. The impact of this change in the vesting schedule is reflected in amendments in the table above.

Information for Pension Plan with Accumulated Benefit Obligation in Excess of Plan Assets for Both Plans

	As of December 31,	
	2011	2010
	(in thousands)	
Projected benefit obligation	$29,480	$23,867
Accumulated benefit obligation	$21,697	$17,457
Less: Fair value of plan assets	13,940	10,332
Underfunded accumulated benefit obligation	$7,757	$7,125

Pension expense is determined based upon the annual service cost of benefits (the actuarial cost of benefits earned during a period) and the interest cost on those liabilities, less the expected return on plan assets. The expected long-term rate on plan assets is applied to a calculated value of plan assets that recognizes changes in fair value over a five-year period. This practice is intended to reduce year-to-year volatility in pension expense, but it can have the effect of delaying recognition of differences between actual returns on assets and expected returns based on long-term rate of return assumptions. Amortization of unrecognized net gain or loss resulting from experience different from that assumed and from changes in assumptions (excluding asset gains and losses not yet reflected in market-related value) is included as a component of net periodic benefit cost for a year. If, as of the beginning of the year, the unrecognized net gain or loss exceeds ten percent of the greater of the projected benefit obligation and the market-related value of plan assets, the amortization is the excess divided by the average remaining service period of participating employees expected to receive benefits under the plan.

Pre-tax amounts not yet recognized in net periodic pension costs, but rather recognized in accumulated other comprehensive loss as of December 31, 2011, and 2010, consist of:

	As of December 31,		
	2011	2010	
	(in thousands)		
Unrecognized actuarial losses	$8,501	$(5,892	)
Unrecognized prior service costs	170	—	
Unrecognized transition obligation	—	—	
Accumulated other comprehensive loss	$8,671	$(5,892	)

The estimated net loss that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $586,000.

Other pre-tax changes recognized in other comprehensive income during 2011, 2010, and 2009, were as follows:

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	As of December 31, 2011	2010	2009
	(in thousands)		
Net actuarial gain (loss)	$(3,014)	$(1,937)	$(239)
Prior service cost	(170)	—	—
Less: Amortization of:			
Actuarial loss	(405)	(367)	(358)
Total other comprehensive income (loss)	$(2,779)	$(1,570)	$119

Components of Net Periodic Benefit Cost for Both Pension Plans

	For the Years Ended December 31, 2011	2010	2009
	(in thousands)		
Components of net periodic benefit cost			
Service cost	$3,800	$3,392	$2,500
Interest cost	1,184	1,120	934
Expected return on plan assets that reduces periodic pension cost	(880)	(638)	(430)
Amortization of prior service cost	—	—	—
Amortization of net actuarial loss	405	367	372
Net periodic benefit cost	$4,509	$4,241	$3,376

Gains and losses in excess of ten percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

Pension Plan Assumptions

Weighted-average assumptions to measure the Company's projected benefit obligation and net periodic benefit cost are as follows:

	As of December 31, 2011	2010	2009
Projected benefit obligation			
Discount rate	4.7%	5.3%	6.1%
Rate of compensation increase	6.2%	6.2%	6.2%
Net periodic benefit cost			
Discount rate	5.3%	6.1%	6.1%
Expected return on plan assets	7.5%	7.5%	7.5%
Rate of compensation increase	6.2%	6.2%	6.2%

The Company's pension investment policy includes various guidelines and procedures designed to ensure that assets are prudently invested in a manner necessary to meet the future benefit obligation of the Pension Plans. The policy does not permit the direct investment of plan assets in the Company's securities. The Company's investment horizon is long-term and accordingly the target asset allocations encompass a strategic, long-term perspective of capital markets, expected risk and return behavior and perceived future economic conditions. The key investment principles of diversification, assessment of risk, and targeting the optimal expected returns for given levels of risk are applied.

The Company's investment portfolio contains a diversified blend of common stocks and bonds, which may

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reflect varying rates of return. The investments are further diversified within each asset classification. The portfolio diversification provides protection against a single security or class of securities having a disproportionate impact on aggregate investment performance. The actual asset allocations are reviewed and rebalanced on a periodic basis to maintain the target allocations. The Company's weighted-average asset allocation for the Qualified Pension Plan is as follows:

	Target		As of December 31,			
Asset Category	2012		2011		2010	
Equity securities	60.0	%	61.8	%	60.8	%
Debt securities	40.0	%	37.7	%	39.2	%
Other	—	%	0.5	%	—	%
Total	100.0	%	100.0	%	100.0	%

There is no asset allocation of the Nonqualified Pension Plan since there are no plan assets in that plan. An expected return on plan assets of 7.5 percent was used to calculate the Company's obligation under the Qualified Pension Plan for 2011 and 2010. Factors considered in determining the expected return include the 60 percent equity and 40 percent debt securities mix of investment of plan assets and the long-term historical rate of return provided by the equity and debt securities markets. The difference in investment income using the projected rate of return compared to the actual rates of return for the past two years was not material and will not have a material effect on the accompanying statements of operations or cash flows from operating activities in future years.

Fair Value Assumptions

The Company's pension plan assets consist of funds that have quoted net asset values within active markets. The individual funds are derived from quoted equity and debt securities within active markets with no judgment involved. As such, the funds are deemed to be Level 1. The fair value of the Company's pension plan assets as of December 31, 2011, utilizing the fair value hierarchy discussed in Note 11 – Fair Value Measurements is as follows:

Assets:	Level 1	Level 2	Level 3
	(in thousands)		
Cash and Money Market Funds	$66	—	—
Equity Securities			
Foreign Large Blend (1)	2,048	—	—
U.S. Small Blend (2)	2,290	—	—
U.S. Large Blend (3)	4,278	—	—
Fixed Income Securities			
Intermediate Term Bond (4)	5,258	—	—
Total	$13,940	—	—

(1) International equities are invested in companies that trade on active exchanges outside the U.S. and are well diversified among a dozen or more developed markets. Active and passive strategies are employed.

(2) U.S. equities are invested in companies that are well diversified by industry sector and equity style, such as growth and value strategies, that trade on active exchanges within the U.S. Active and passive management strategies are employed. At least 80% of this fund is invested in equity securities of small companies.

(3) U.S. equities include companies that are well diversified by industry sector and equity style, such as growth and value strategies, that trade on active exchanges within the U.S. Active and passive management strategies are employed. At least 80% of this fund is invested in equity securities designed to replicate the holdings and weightings of the stocks listed in the S&P 500 index.

(4) Intermediate term bonds seek total return. At least 80% of this fund is invested in a diversified portfolio of bonds, which include all types of securities. It invests primarily in bonds of corporate and governmental issues located in the U.S. and foreign countries, including emerging markets all of which trade on active exchanges.

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The fair value of the Company’s pension plan assets as of December 31, 2010, is as follows (see footnotes above):

Assets:	Level 1	Level 2	Level 3
	(in thousands)		
Cash and Money Market Funds	$4	$—	$—
Equity Securities			
Foreign Large Blend (1)	1,444	—	—
U.S. Small Blend (2)	1,647	—	—
U.S. Large Blend (3)	3,185	—	—
Fixed Income Securities			
Intermediate Term Bond (4)	4,052	—	—
Total	$10,332	$—	$—

Contributions

The Company contributed $5.3 million, $1.7 million, and $2.0 million, to the Pension Plans in the years ended December 31, 2011, 2010, and 2009, respectively. The Company is expected to make a $4.9 million contribution to the Pension Plans in 2012.

Benefit Payments

The Pension Plans made actual benefit payments of $1.5 million, $1.7 million, and $945,000 in the years ended December 31, 2011, 2010, and 2009, respectively. Expected benefit payments over the next ten years are as follows (in thousands):

Years Ending December 31,	
2012	$1,296
2013	2,360
2014	2,513
2015	2,205
2016	2,668
2017 through 2021	$23,258

Note 9 – Asset Retirement Obligations

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company’s accompanying consolidated statements of cash flows.

The Company’s estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using the credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company’s abandonment liabilities range from 6.5 percent to 12 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives or if federal or state regulators enact new requirements

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regarding the abandonment of wells.

A reconciliation of the Company's asset retirement obligation liability is as follows:

	As of December 31,	
	2011	2010
	(in thousands)	
Beginning asset retirement obligation	$82,849	$102,080
Liabilities incurred	5,465	4,738
Liabilities settled	(8,365)	(30,523)
Accretion expense	5,948	5,583
Revision to estimated cash flows	10,009	971
Ending asset retirement obligation	$95,906	$82,849

As of December 31, 2011, and 2010, the Company had $1.3 million and $2.1 million, respectively, of asset retirement obligation associated with the oil and gas properties held for sale included in a separate line item on the Company's accompanying balance sheets. Additionally, as of December 31, 2011, and 2010, accounts payable and accrued expenses contain $7.5 million and $11.7 million, respectively, related to the Company's current asset retirement obligation liability for estimated plugging and abandonment costs associated with platforms that are being relinquished or retired.

Note 10 – Derivative Financial Instruments

Oil, Natural Gas, and NGL Commodity Hedges

To mitigate a portion of the exposure to potentially adverse market changes in commodity prices and the associated impact on cash flows, the Company has entered into various commodity derivative contracts. The Company's derivative contracts in place include swap and collar arrangements for oil, natural gas, and NGLs. As of December 31, 2011, the Company has commodity derivative contracts in place through the second quarter of 2014 for a total of 7.5 million Bbls of oil, 56.7 million MMBtu of gas, and 1.3 million Bbls of NGLs. As of February 16, 2012, the Company had commodity derivative contracts in place through the fourth quarter of 2014 for a total of 11.0 million Bbls of oil, 77.9 million MMBtu of gas, and 1.5 million Bbls of NGLs.

The Company's commodity derivatives are measured at fair value and are included in the accompanying balance sheets as derivative assets and liabilities. The Company derives internal valuation estimates that take into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The pertinent factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments. The derivative instruments utilized by the Company are not considered by management to be complex, structured, or illiquid. The commodity derivative markets are highly active. The fair value of the commodity derivative contracts was a net asset of $31.2 million and a net liability of $52.3 million at December 31, 2011, and December 31, 2010, respectively.

Discontinuance of Cash Flow Hedge Accounting

Prior to January 1, 2011, the Company designated its commodity derivative contracts as cash flow hedges, for which unrealized changes in fair value were recorded to accumulated other comprehensive income (loss) ("AOCIL"), to the extent the hedges were effective. As of January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges at December 31, 2010. As a result, subsequent to December 31, 2010, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCIL. The Company decided to discontinue the use of hedge accounting prospectively.

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At December 31, 2010, accumulated other comprehensive loss ("AOCL") included $11.8 million of unrealized losses net of income tax, representing the change in fair value of the Company's open commodity derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2011, such fair values at December 31, 2010, were frozen in AOCL as of the de-designation date and are reclassified into earnings as the original derivative transactions settle. During the year ended December 31, 2011, $13.0 million of, net of income tax, derivative losses relating to de-designated commodity hedges were reclassified from AOCL into earnings. As of December 31, 2011, AOCL included $1.1 million of, net of income tax, unrealized gains on commodity derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL a $2.4 million gain, net of income tax, related to de-designated commodity derivative contracts during the next twelve months.

Please refer to Note 11 – Fair Value Measurements for more information regarding the Company's derivative instruments. The following table details the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of December 31, 2011			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$55,813	Current Liabilities	$42,806
Commodity Contracts	Noncurrent Assets	31,062	Noncurrent liabilities	12,875
Derivatives not designated as hedging instruments		$86,875		$55,681

	As of December 31, 2010			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in thousands)			
Commodity Contracts	Current Assets	$43,491	Current Liabilities	$82,044
Commodity Contracts	Noncurrent Assets	18,841	Noncurrent Liabilities	32,557
Derivatives designated as hedging instruments		$62,332		$114,601

The following table summarizes the unrealized and realized gains and losses on derivative cash settlements and changes in fair value of derivative contracts not designated as hedging instruments as presented in the accompanying statements of operations.

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	For the year ended December 31, 2011 (in thousands)
Cash settlement (gain) loss:	
Oil contracts	$22,633
Natural gas contracts	(10,711)
NGL contracts	13,749
Total cash settlement loss	$25,671
Unrealized (gain) loss on changes in fair value:	
Oil contracts	$(3,391)
Natural gas contracts	(64,310)
NGL contracts	4,944
Total net unrealized (gain) on change in fair value	$(62,757)
Total unrealized and realized derivative (gain) loss	$(37,086)

The following table details the effect of derivative instruments on AOCIL and the accompanying statements of operations (net of income tax):

	Derivatives	Location on Accompanying Statements of Operations	For the Years Ended December 31,		
			2011	2010	2009
			(in thousands)		
Amount reclassified from AOCIL to realized hedge (loss) gain	Commodity Contracts	Realized hedge (loss) gain	$12,997	$6,641	$(67,344)

The realized net hedge loss for the year ended December 31, 2011, is comprised of realized cash settlements on commodity derivative contracts that were previously designated as cash flow hedges, whereas the realized net hedge gain for the years ended December 31, 2010 and 2009, is comprised of realized cash settlements on all commodity derivative contracts. Realized hedge gains or losses from the settlement of commodity derivatives previously designated as cash flow hedges are reported in the total operating revenues and other income section of the accompanying statements of operations. The Company realized a net loss of $20.7 million, a net gain of $23.5 million, and a net gain of $140.6 million from its commodity derivative contracts for the years ended December 31, 2011, 2010, and 2009, respectively.

As noted above, effective January 1, 2011, the Company elected to de-designate all of its commodity derivative contracts that had been previously designated as cash flow hedges, and as such no new gains or losses are deferred in AOCIL at December 31, 2011. The following table details the effect of derivative instruments on AOCIL and the accompanying balance sheets (net of income tax):

	Derivatives	Location on Accompanying Balance Sheets	For the years ended December 31,	
			2010	2009
			(in thousands)	
Amount of gain (loss) on derivatives recognized in AOCIL during the period (effective portion)	Commodity Contracts	AOCIL	$16,811	$(35,977)

The Company has no derivatives designated as cash flow hedges at December 31, 2011. The following table details the ineffective portion of derivative instruments classified as cash flow hedges on the accompanying

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statements of operations for the years ended December 31, 2010 and 2009.

Derivatives Qualifying as Cash Flow Hedges	Location on Accompanying Statements of Operations	Loss Recognized in Earnings (Ineffective Portion) For the Years Ended December 31,	
		2010	2009
		(in thousands)	
Commodity Contracts	Unrealized and realized derivative (gain) loss	$8,899	$20,469

Credit Related Contingent Features

As of December 31, 2011, and through the filing date of this report, all of the Company's derivative counterparties were members of the Company's credit facility syndicate. The Company's credit facility is secured by liens on substantially all of the Company's proved oil and gas properties.

Convertible Note Derivative Instrument

The contingent interest provision of the 3.50% Senior Convertible Notes is an embedded derivative instrument. As of December 31, 2011 and 2010, the value of this derivative was determined to be immaterial.

Note 11 – Fair Value Measurements

The Company follows fair value measurement authoritative accounting guidance for all assets and liabilities measured at fair value. That authoritative accounting guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Market or observable inputs are the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The hierarchy for grouping these assets and liabilities is based on the significance level of the following inputs:

- Level 1 – Quoted prices in active markets for identical assets or liabilities
- Level 2 – Quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar instruments in markets that are not active, and model-derived valuations whose inputs are observable or whose significant value drivers are observable
- Level 3 – Significant inputs to the valuation model are unobservable

The following is a listing of the Company's assets and liabilities that are measured at fair value and where they are classified within the hierarchy as of December 31, 2011:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives (1)	$—	$86,875	$—
Proved oil and gas properties (2)	$—	$—	$139,992
Unproved oil and gas properties (2)	—	—	15,809
Liabilities:			
Derivatives (1)	$—	$55,681	$—
Net Profits Plan (1)	$—	$—	$107,731

(1) This represents a financial asset or liability that is measured at fair value on a recurring basis.

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(2) This represents a non-financial asset that is measured at fair value on a nonrecurring basis.

The following is a listing of the Company's financial assets and liabilities that are measured at fair value on a recurring basis and where they are classified within the hierarchy as of December 31, 2010:

	Level 1	Level 2	Level 3
	(in thousands)		
Assets:			
Derivatives	$—	$62,332	$—
Liabilities:			
Derivatives	$—	$114,601	$—
Net Profits Plan	$—	$—	$135,850

Both financial and non-financial assets and liabilities are categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The following is a description of the valuation methodologies used by the Company as well as the general classification of such instruments pursuant to the hierarchy. There were no non-financial assets or liabilities measured at fair value on a nonrecurring basis at December 31, 2010.

Derivatives

The Company uses Level 2 inputs to measure the fair value of oil, gas, and NGL commodity derivatives. Fair values are based upon interpolated data. The Company derives internal valuation estimates taking into consideration the counterparties' credit ratings, the Company's credit rating, and the time value of money. These valuations are then compared to the respective counterparties' mark-to-market statements. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing derivative instruments.

Generally, market quotes assume that all counterparties have near zero, or low, default rates and have equal credit quality. However, an adjustment may be necessary to reflect the credit quality of a specific counterparty to determine the fair value of the instrument. The Company monitors the credit ratings of its counterparties and may ask counterparties to post collateral if their ratings deteriorate. In some instances the Company will attempt to novate the trade to a more stable counterparty.

Valuation adjustments are necessary to reflect the effect of the Company's credit quality on the fair value of any liability position with a counterparty. This adjustment takes into account any credit enhancements, such as collateral margin that the Company may have posted with a counterparty, as well as any letters of credit between the parties. The methodology to determine this adjustment is consistent with how the Company evaluates counterparty credit risk, taking into account the Company's credit rating, current credit facility margins, and any change in such margins since the last measurement date. All of the Company's derivative counterparties are members of the Company's credit facility bank syndicate.

The methods described above may result in a fair value estimate that may not be indicative of net realizable value or may not be reflective of future fair values and cash flows. While the Company believes that the valuation methods utilized are appropriate and consistent with authoritative accounting guidance and with other marketplace participants, the Company recognizes that third parties may use different methodologies or assumptions to determine the fair value of certain financial instruments that could result in a different estimate of fair value at the reporting date.

Net Profits Plan

The Net Profits Plan is a standalone liability for which there is no available market price, principal market, or market participants. Certain inputs for this instrument are unobservable and are therefore classified as Level 3 inputs. The Company employs the income approach, which converts expected future cash flow amounts to a single present value amount. This technique uses the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk to calculate the fair value. There is a direct correlation between realized oil, gas, and NGL commodity prices driving net cash flows and the Net Profits Plan liability. Generally, higher commodity prices result in a larger Net Profits Plan liability and vice versa.

The Company records the estimated fair value of the long-term liability for estimated future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. For those pools currently in payout, a discount rate of 12 percent is used to calculate this liability. A discount rate of 15 percent is being used to calculate the liability for pools that have not reached payout. These rates are intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan.

The Company's estimate of its liability is highly dependent on commodity prices, cost assumptions, and the discount rates used in the calculations. The Company continually evaluates the assumptions used in this calculation in order to consider the current market environment for oil, gas, and NGL prices, costs, discount rates, and overall market conditions. The Net Profits Plan liability is determined using price assumptions of five one-year strip prices with the fifth year's pricing then carried out indefinitely. The average price is adjusted for realized price differentials and to include the effects of forecasted production covered by derivative contracts in the relevant periods. The non-cash expense associated with this significant management estimate is highly volatile from period to period due to fluctuations that occur in the oil, gas, and NGL commodity markets.

If the commodity prices used in the calculation changed by five percent, the liability recorded at December 31, 2011, would differ by approximately $9 million. A one percentage point change in the discount rate would result in a change to the liability of approximately $5 million. Actual cash payments to be made to participants in future periods are dependent on realized actual production, realized commodity prices, and actual costs associated with the properties in each individual pool of the Net Profits Plan. Consequently, actual cash payments are inherently different from the amounts estimated.

No published market quotes exist on which to base the Company's estimate of fair value of the Net Profits Plan liability. As such, the recorded fair value is based entirely on management estimates that are described within this footnote. While some inputs to the Company's calculation of fair value on the Net Profits Plan's future payments are from published sources, others, such as the discount rate and the expected future cash flows, are derived from the Company's own calculations and estimates. The following table reflects the activity for the Net Profits Plan liability measured at fair value using Level 3 inputs:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Beginning balance	$135,850	$170,291	$177,366
Net increase in liability [1]	2,269	14,063	13,511
Net settlements [1] [2] [3]	(30,388)	(48,504)	(20,586)
Transfers in (out) of Level 3	—	—	—
Ending balance	$107,731	$135,850	$170,291

(1) Net changes in the Net Profits Plan liability are shown in the Change in Net Profits Plan liability line item of the accompanying statements of operations.

(2) Settlements represent cash payments made or accrued under the Net Profits Plan. The Company accrued or made cash payments under the Net Profits Plan relating to divestiture proceeds of $6.3 million, $26.1 million, and $724,000 for the years ended December 31, 2011, 2010, and 2009 respectively.

(3) During the first quarter of 2011, the Company elected to cash out several Net Profits Plan pools associated with the acquisition of Nance Petroleum Corporation in 1999, through a $2.6 million direct payment. As a result, the Company reduced its Net Profits Plan liability by that amount. There is no impact on the accompanying statements of operations for

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the period ended December 31, 2011, related to these settlements.

Long-term Debt

Based on the secondary market trading price of the 3.50% Senior Convertible Notes, the estimated fair value of the notes was approximately $394 million and $351 million as of December 31, 2011, and 2010, respectively. The fair value of the embedded contingent interest derivative was immaterial as of December 31, 2011, and 2010.

Based on the secondary market trading price, the fair market value of the 6.625% Senior Notes and the 6.50% Senior Notes as of December 31, 2011, was approximately $359 million and $360 million, respectively.

Proved Oil and Gas Properties

Proved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses Level 3 inputs and the income valuation technique, which converts future amounts to a single present value amount, to measure the fair value of proved properties through an application of discount rates and price forecasts selected by the Company's management. The calculation of the discount rate is based on the best information available and estimated to be 12 percent for the year ended December 31, 2011. Management believes that the discount rate is representative of current market conditions and considers the estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk. The price forecast is based on NYMEX strip pricing, adjusted for basis differentials, for the first five years. At the end of the first five years, a flat terminal price is used. Future operating costs are also adjusted as deemed appropriate for these estimates.

As a result of asset write-downs discussed in Note 1 - Summary of Significant Accounting Policies and Note 3 - Divestitures and Assets Held for Sale, the proved oil and gas properties measured at fair value within the accompanying balance sheets were $140.0 million as of December 31, 2011. There were no proved oil and gas properties measured at fair value at December 31, 2010.

Unproved Oil and Gas Properties

Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. The Company uses a market approach and Level 3 inputs to measure the fair value of unproved properties. The calculation of the discount rate is based on the best information available and estimated to be 12 percent for the year ended December 31, 2011. Management believes that the discount rate is representative of current market conditions and includes the following factors: estimate of future cash payments, expectations of possible variations in the amount and/or timing of cash flows, the risk premium, and nonperformance risk.

As a result of the asset write-downs discussed in Note 3 - Divestitures and Assets Held for Sale, the unproved oil and gas properties measured at fair value within the accompanying balance sheets were $15.8 million as of December 31, 2011. There were no unproved oil and gas properties measured at fair value at December 31, 2010.

Materials Inventory

Materials inventory is valued at the lower of cost or market. The Company uses Level 2 inputs to measure the fair value of materials inventory, which is primarily comprised of tubular goods. The Company uses third party market quotes and compares the quotes to the book value of the materials inventory. If the book value exceeds the quoted market price, the Company reduces the book value to the market price. The considered factors result in an estimated exit-price that management believes provides a reasonable and consistent methodology for valuing materials inventory. There were no materials inventory measured at fair value within the accompanying balance sheets at December 31, 2011, and 2010.

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Asset Retirement Obligations

The income valuation technique is utilized by the Company to determine the fair value of the asset retirement obligation liability at the point of inception by applying a credit-adjusted risk-free rate, which takes into account the Company's credit risk, the time value of money, and the current economic state, to the undiscounted expected abandonment cash flows. Given the unobservable nature of the inputs, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. There were no asset retirement obligations measured at fair value within the accompanying balance sheets at December 31, 2011 and 2010.

Please refer to Note 10 – Derivative Financial Instruments and Note 9 – Asset Retirement Obligations for more information regarding the Company's derivative instruments and asset retirement obligations.

Note 12 - Acquisition and Development Agreement and Carry and Earning Agreement

Acquisition and Development Agreement

In June 2011, the Company entered into an Acquisition and Development Agreement with Mitsui E&P Texas LP ("Mitsui"), an indirect subsidiary of Mitsui & Co., Ltd (the "Acquisition and Development Agreement"). Pursuant to the Acquisition and Development Agreement, the Company agreed to transfer to Mitsui a 12.5 percent working interest in certain non-operated oil and gas assets representing approximately 39,000 net acres in Dimmit, LaSalle, Maverick, and Webb Counties, Texas. As consideration for the oil and gas interests transferred, Mitsui agreed to pay, or carry, 90 percent of certain drilling and completion costs attributable to the Company's remaining interest in these assets following the closing of the transaction, until Mitsui has expended an aggregate $680.0 million on behalf of the Company. Based on the Company's forecast of the operator's drilling plans, it will take three to four years to fully utilize the carry. The agreement also provided for the conveyance of one-half of the Company's ownership in related gathering assets in exchange for the reimbursement by Mitsui of 50 percent of costs incurred on those assets by the Company through the closing date. The effective date of the transfer was March 1, 2011, and the transaction closed on December 2, 2011. Mitsui has reimbursed the Company for capital expenditures and other costs, net of revenues, that the Company paid and attributable to the transferred interest during the period between the effective date and the closing date. The Company will apply these reimbursed costs to the remaining ten percent of the Company's drilling and completion costs for the affected acreage.

As of December 31, 2011, the Company received $124.7 million of cash payments from Mitsui that are contractually restricted to be used solely for development operations pursuant to the Acquisition and Development Agreement and accordingly are classified as non-current assets. The Company has recorded a corresponding liability equal to the restricted cash balance. The portion of the liability related to development operations expected to occur within the next year is recorded in accounts payable and accrued expenses within the accompanying balance sheets. The portion of the liability related to development operations expected to occur more than one year in the future is recorded in other noncurrent liabilities within the accompanying balance sheets as of December 31, 2011. There was no net impact on the accompanying consolidated statement of cash flows as restricted cash was offset against the corresponding liability in investing activities. None of the carry had been utilized as of year-end. Legal and commission costs associated with the execution of the arrangement were recorded as other operating expense in the accompanying statements of operations.

Carry and Earning Agreement

On April 29, 2010, the Company entered into a Carry and Earning Agreement, which effectively provided for a third party to earn 95 percent of SM Energy's interest in approximately 8,400 net acres in a portion of the Company's East Texas Haynesville shale acreage, as well as an interest in several wells and five percent of SM Energy's interest in approximately 23,400 net acres in a separate portion of the Company's Haynesville acreage in East Texas. In exchange for these interests, the third party invested $91.3 million to fund the drilling and completion costs of horizontal wells in the portion of the leases where the Company retained 95 percent of its interest. The parties now share all costs of operations within the area of joint ownership in accordance with their respective ownership interests.

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Note 13 - Suspended Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2011, 2010, and 2009. The table does not include amounts that were capitalized and either subsequently expensed or reclassified to producing well costs in the same year:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Beginning balance on January 1,	$35,862	$34,384	$9,437
Additions to capitalized exploratory well costs pending the determination of proved reserves	15,618	35,862	34,384
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	(32,880)	(34,384)	(7,569)
Capitalized exploratory well costs charged to expense	—	—	(1,868)
Ending balance at December 31,	$18,600	$35,862	$34,384

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of projects for which exploratory well costs have been capitalized for more than one year since the completion of drilling:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Exploratory well costs capitalized for one year or less	$15,618	$35,862	$34,384
Exploratory well costs capitalized for more than one year	2,982	—	—
Ending balance at December 31,	$18,600	$35,862	$34,384
Number of projects with exploratory well costs that have been capitalized more than a year	2	—	—

The table above consists of two exploratory wells located in our Permian region. The Company drilled successful surrounding test wells in the same prospect as the above wells in late 2011 and early 2012 to assess the value of re-entering these exploratory wells to target the formation through horizontal drilling. Minimal capital has been spent on these wells during the year due to further development of the prospect using horizontal drilling. Management is currently analyzing the economics of advancing this project.

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Supplemental Oil and Gas Information (unaudited)

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, whether capitalized or expensed, are summarized as follows:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Development costs	$1,208,255	$299,308	$213,971
Facility costs	112,372	80,328	9,137
Exploration costs	177,465	443,888	154,122
Acquisitions			
Proved properties	—	664	76
Leasing activity	55,237	53,192	41,677
Total, including asset retirement obligation[1][2]	$1,553,329	$877,380	$418,983

(1) Includes capitalized interest of $10.8 million, $4.3 million, and $1.9 million for the years ended December 31, 2011, 2010, and 2009, respectively.

(2) Includes amounts relating to estimated asset retirement obligations of $19.3 million, $5.8 million, and $(805,000) for the years ended December 31, 2011, 2010, and 2009, respectively.

Oil and Gas Reserve Quantities

The reserve estimates presented below were made in accordance with oil and gas reserve estimation and disclosure authoritative accounting guidance issued by the FASB effective for reporting periods ending on or after December 31, 2009. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC's " Modernization of Oil and Gas Reporting " rule, which was also effective for annual reports for fiscal years ending on or after December 31, 2009.

Proved reserves are the estimated quantities of oil, gas, and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined, and the price to be used is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. All of the Company’s estimated proved reserves are located in North America.

The table below presents a summary of changes in the Company's estimated proved reserves for each of the years in the three-year period ended December 31, 2011. The Company engaged Ryder Scott to audit internal engineering estimates for at least 80 percent of the PV-10 value of our estimated proved reserves in each year presented. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

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	For the Years Ended December 31,								
	2011[1]			2010[2]			2009[3]		
	Oil (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil or Condensate (MMBbl)	Gas (Bcf)	NGLs (MMBbl)	Oil or Condensate (MMBbl)	Gas (Bcf)	NGLs (MMBbl)
Total proved reserves									
Beginning of year	57.4	640.0	—	53.8	449.5	—	51.4	557.4	—
Revisions of previous estimate	(0.9)	(76.7)	15.6	3.1	6.1	—	4.5	(76.8)	—
Discoveries and extensions	26.9	223.5	17.8	16.2	172.9	—	3.4	51.9	—
Infill reserves in an existing proved field	2.8	14.8	0.5	2.8	97.2	—	1.2	29.9	—
Sales of reserves[4]	(6.4)	(37.3)	(2.9)	(12.1)	(14.0)	—	(0.4)	(41.8)	—
Purchases of minerals in place	—	—	—	—	0.2	—	—	—	—
Production	(8.1)	(100.3)	(3.5)	(6.4)	(71.9)	—	(6.3)	(71.1)	—
End of year [5]	71.7	664.0	27.5	57.4	640.0	—	53.8	449.5	—
Proved developed reserves									
Beginning of year	46.0	411.0	—	48.1	342.0	—	47.1	433.2	—
End of year	50.3	451.2	15.2	46.0	411.0	—	48.1	342.0	—
Proved undeveloped reserves									
Beginning of year	11.4	229.0	—	5.7	107.5	—	4.3	124.2	—
End of year	21.4	212.8	12.3	11.4	229.0	—	5.7	107.5	—

(1) Please refer to Part I, Item 1 and 2 and Part II, Item 7 for current year reserve discussion.

(2) For the year ended December 31, 2010, of the 24.7 BCFE upward revision of previous estimate, 42.6 BCFE and (17.9) BCFE relate to price and performance revisions, respectively. The prices used in the calculation of proved reserve estimates as of December 31, 2010, were $79.43 per Bbl and $4.38 per MMBtu for oil and natural gas, respectively. These prices were 30 percent and 13 percent higher, respectively, than the prices used in 2009. Performance revisions in 2010 resulted in a net 11.2 BCFE decrease in our estimate of proved reserves. While the Company recognized positive performance revisions in every region on proved developed properties, we had approximately 19.3 BCFE of negative performance revisions related to estimated proved undeveloped reserves in primarily dry gas assets, resulting from lower gas prices and higher well costs on the economics of these assets. The Company added 384.2 BCFE from its drilling program, included in discoveries and extensions and infill reserves, the majority which related to its activity in the Eagle Ford shale in South Texas.

(3) For the year ended December 31, 2009, of the 49.6 BCFE downward revision of previous estimate, 12.0 BCFE and (61.6) BCFE relate to price and performance revisions, respectively. The largest portion of the performance revision related to producing properties in the Company's Wolfberry tight oil program in the Permian Basin in West

Texas. Well performance data collected during 2009 at the Sweetie Peck and Halff East programs that target the Wolfberry interval indicated that these assets were underperforming for year-end 2008 decline forecasts.

(4) The Company divested of certain non-core assets during 2011, 2010, and 2009. Please refer to Note 3 - Divestitures and Assets Held for Sale for additional information.

(5) For the years ended December 31, 2011, 2010, and 2009, amounts included approximately 175, 356, and 370 MMcf respectively, representing the Company’s net underproduced gas balancing position.

Note: Prior to 2011, we reported our natural gas production as a single stream of rich gas measured at the well head.

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Beginning in the first quarter of 2011, we changed our reporting for natural gas volumes to separately show natural gas and NGL production volumes, revenues, and pricing consistent with title transfer for each product. Please refer to additional discussion above under the caption Oil, Gas, and NGL Prices.

Standardized Measure of Discounted Future Net Cash Flows

The Company computes a standardized measure of future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated future reserve quantities. Each property the Company operates is also charged with field-level overhead in the estimated reserve calculation. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a ten percent annual discount factor.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions, plus Company overhead incurred by the central administrative office attributable to operating activities.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company’s expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure:

	2011	2010	2009
Gas (per Mcf)	$4.72	$5.54	$3.82
Oil (per Bbl)	$88.00	$70.60	$53.94
NGLs (per Bbl)	$51.95	$—	$—

The following summary sets forth the Company’s future net cash flows relating to proved oil, gas, and NGL reserves based on the standardized measure.

	As of December 31,		
	2011	2010	2009
	(in thousands)		
Future cash inflows	$10,871,281	$7,598,159	$4,620,735
Future production costs	(3,786,887)	(2,512,091)	(1,968,096)
Future development costs	(1,036,352)	(789,493)	(387,722)
Future income taxes	(1,740,394)	(1,335,576)	(515,953)
Future net cash flows	4,307,648	2,960,999	1,748,964
10 percent annual discount	(1,727,608)	(1,294,632)	(732,997)
Standardized measure of discounted future net cash flows	$2,580,040	$1,666,367	$1,015,967

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The principle sources of change in the standardized measure of discounted future net cash flows are:

	For the Years Ended December 31,		
	2011	2010	2009
	(in thousands)		
Standardized measure, beginning of year	$1,666,367	$1,015,967	$1,059,069
Sales of oil, gas, and NGLs produced, net of production costs	(1,042,281)	(641,213)	(409,153)
Net changes in prices and production costs	454,646	557,681	154,008
Extensions, discoveries and other including infill reserves in an existing proved field, net of production costs	1,816,640	989,365	166,666
Sales of reserves in place	(369,820)	(151,315)	(44,823)
Purchase of reserves in place	—	804	-
Development costs incurred during the year	49,246	43,900	33,742
Changes in estimated future development costs	(31,410)	49,531	75,134
Revisions of previous quantity estimates	32,992	66,759	(96,354)
Accretion of discount	234,433	128,408	126,538
Net change in income taxes	(203,169)	(409,848)	(61,801)
Changes in timing and other	(27,604)	16,328	12,941
Standardized measure, end of year	$2,580,040	$1,666,367	$1,015,967

Quarterly Financial Information (unaudited)

The Company's quarterly financial information for fiscal years 2011 and 2010 is as follows (in thousands, except per share amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year Ended December 31, 2011				
Total operating revenues	$315,329	$377,873	$530,574	$379,542
Total operating expenses	335,301	166,166	157,786	559,681
Income (loss) from operations	$(19,972)	$211,707	$372,788	$(180,139)
Income (loss) before income taxes	$(29,558)	$197,384	$363,443	$(192,268)
Net income (loss)	$(18,503)	$124,533	$230,097	$(120,711)
Basic net income (loss) per common share	$(0.29)	$1.96	$3.60	$(1.89)
Diluted net income (loss) per common share	$(0.29)	$1.86	$3.41	$(1.89)
Dividends declared per common share	$0.05	$—	$0.05	$—
Year Ended December 31, 2010				
Total operating revenues	$360,135	$211,697	$226,884	$294,118
Total operating expenses	152,384	174,908	195,832	230,939
Income from operations	$207,751	$36,789	$31,052	$63,179
Income before income taxes	$201,093	$30,500	$24,798	$58,505
Net income	$126,178	$18,068	$15,452	$37,139
Basic net income per common share	$2.01	$0.29	$0.25	$0.59
Diluted net income per common share	$1.96	$0.28	$0.24	$0.56
Dividends declared per common share	$0.05	$—	$0.05	$—

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures that are designed to reasonably ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and to reasonably ensure that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. The Company’s internal control over financial reporting is 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. The Company’s internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and

(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that have a material effect on the financial statements.

Because of the inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. 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 the changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework.

Based on our assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2011.

The Company’s independent registered public accounting firm has issued an attestation report on the Company’s internal controls over financial reporting. That report immediately follows this report.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
SM Energy Company and Subsidiaries
Denver, Colorado

We have audited the internal control over financial reporting of SM Energy Company and subsidiaries (the “Company”) 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 Company’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 Report on Internal Control 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 by, or under the supervision of, the company’s principal executive and principal financial officers, or persons performing similar functions, and effected by the company’s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011, of the Company and our report dated February 23, 2012, expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP
Denver, Colorado
February 23, 2012

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The information required by this Item concerning SM Energy's Directors and corporate governance is incorporated by reference to the information provided under the captions Structure of the Board of Directors, Proposal 1 - Election of Directors, and Corporate Governance in SM Energy's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from December 31, 2011.

The information required by this Item concerning compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the information provided under the caption Section 16(a) Beneficial Ownership Reporting Compliance in SM Energy's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from December 31, 2011.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth the names, ages and positions held by SM Energy's executive officers. The ages of our executive officers are listed as of February 16, 2012.

Name	Age	Position
Anthony J. Best	62	Chief Executive Officer and President
Javan D. Ottoson	53	Executive Vice President and Chief Operating Officer
A. Wade Pursell	46	Executive Vice President and Chief Financial Officer
David W. Copeland	55	Senior Vice President, General Counsel and Corporate Secretary
Gregory T. Leyendecker	54	Senior Vice President and Regional Manager
Mark D. Mueller	47	Senior Vice President and Regional Manager
Lehman E. Newton, III	56	Senior Vice President and Regional Manager
Paul M. Veatch	45	Senior Vice President and Regional Manager
Mark T. Solomon	43	Vice President and Controller
Dennis A. Zubieta	45	Vice President – Engineering and Evaluation

Anthony J. Best. Mr. Best joined the Company in June 2006 as President and Chief Operating Officer. In December 2006, Mr. Best relinquished his position as Chief Operating Officer when Javan D. Ottoson was elected to that office. Mr. Best was elected Chief Executive Officer of the Company in February 2007. From November 2005 to June 2006, Mr. Best was developing a business plan and securing capital commitments for a new exploration and production entity. From 2003 to October 2005, Mr. Best was President and Chief Executive Officer of Pure Resources, Inc., an independent oil and natural gas exploration and production company that was a subsidiary of Unocal, where he managed all of Unocal's onshore U.S. assets. From 2000 to 2002, Mr. Best had an oil and gas consulting practice, working with various energy firms. From 1979 to 2000, Mr. Best was with ARCO in a variety of positions, including serving as President - ARCO Latin America, President - ARCO Permian, Field Manager for Prudhoe Bay and VP - External Affairs for ARCO Alaska. Mr. Best has over 30 years of experience in the energy industry.

Javan D. Ottoson. Mr. Ottoson joined the Company in December 2006 as Executive Vice President and Chief Operating Officer. Mr. Ottoson has been in the energy industry for over 30 years. From April 2006 until he joined the Company in December 2006, Mr. Ottoson was Senior Vice President - Drilling and Engineering at Energy Partners, Ltd., an independent oil and natural gas exploration and production company, where his responsibilities included overseeing all aspects of its drilling and engineering functions. Mr. Ottoson managed

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Permian Basin assets for Pure Resources, Inc., a Unocal subsidiary, and its successor owner, Chevron, from July 2003 to April 2006. From April 2000 to July 2003, Mr. Ottoson owned and operated a homebuilding company in Colorado and ran his family farm. Prior to 2000 Mr. Ottoson worked for ARCO in a variety of management and operational roles, including serving as President of ARCO China, Commercial Director of ARCO United Kingdom, and Vice President of Operations and Development, ARCO Permian.

A. Wade Pursell. Mr. Pursell joined the Company in September 2008 as Executive Vice President and Chief Financial Officer. Mr. Pursell was Executive Vice President and Chief Financial Officer for Helix Energy Solutions Group, Inc., a global provider of life-of-field services and development solutions to offshore energy producers and an oil and gas producer, from February 2007 to September 2008. From October 2000 to February 2007, he was Senior Vice President and Chief Financial Officer of Helix. He joined Helix in May 1997, as Vice President—Finance and Chief Accounting Officer. From 1988 through May 1997, Mr. Pursell was with Arthur Andersen LLP, serving lastly as an Experienced Manager specializing in the offshore services industry. Mr. Pursell has over 24 years of experience in the energy industry.

David W. Copeland. Mr. Copeland joined the Company in January 2011 as Senior Vice President and General Counsel. He was appointed as the Company's Corporate Secretary in July 2011. Mr. Copeland has over 30 years of experience in the legal profession, including over 20 years as internal counsel for various energy companies. Prior to joining the Company, he co-founded Concho Resources Inc., in Midland, Texas, where he served as its Vice President, General Counsel and Secretary from April 2004 through November 2009, and then as its Senior Counsel through December 2010. From August 1997 through March 2004, Mr. Copeland served as an executive officer and general counsel of two other energy companies he co-founded with others in Midland, Texas. Mr. Copeland started his career in 1982 with the Stubbeman, McRae, Sealy, Laughlin & Browder law firm in Midland, Texas.

Gregory T. Leyendecker. Mr. Leyendecker was appointed Senior Vice President and Regional Manager in May 2010. From July 2007 to May 2010, he served as Vice President and Regional Manager. Mr. Leyendecker joined the Company in December 2006 as Operations Manager for the South Texas & Gulf Coast Region in Houston, Texas. Mr. Leyendecker has over 31 years in the energy industry, and held various positions with Unocal Corporation, an independent oil and natural gas exploration and production company, from 1980 until its acquisition in 2005. During his career with Unocal, he was the Asset Manager for Unocal Gulf Region USA from 2003 to June 2004 and Production and Reservoir Engineering Technology Manager for Unocal from June 2004 to August 2005. He was appointed Drilling and Workover Manager for the San Joaquin Valley business unit of Chevron, as successor-by-merger of Unocal Corporation, in Bakersfield, California in August 2005, and held this position until January 2006. Immediately prior to joining the Company, Mr. Leyendecker was Vice President of Drilling Management Services from February 2006 to November 2006 for Enventure Global Technology, a provider of solid expandable tubular technology.

Mark D. Mueller. Mr. Mueller joined the Company in September 2007 as Senior Vice President. Mr. Mueller was appointed as the Regional Manager of the Rocky Mountain Region effective January 1, 2008. Mr. Mueller has been in the energy industry for over 25 years. From September 2006 to September 2007, he was Vice President and General Manager at Samson Exploration Ltd., an oil and gas exploration and production company that was a subsidiary of Samson Investment Company, in Calgary, Canada, where his responsibilities included fiscal performance, reserves, and all operational functions of the company. From April 2005 until its sale in August 2006, Mr. Mueller was Vice President and General Manager for Samson Canada Ltd., an oil and gas exploration and production company that was a subsidiary of Samson Investment Company, where he was responsible for all business units and the eventual sale of the company. Mr. Mueller joined Samson Canada Ltd. as Project Manager in May 2003 to build a new basin-centered gas business unit and was Vice President from December 2003 to August 2006. Prior to joining Samson, Mr. Mueller was West Central Alberta Engineering Manager for Northrock Resources Ltd., a Canadian oil and gas company that was a wholly-owned subsidiary of Unocal Corporation, in Calgary, Canada. From 1986 to 2003, Mr. Mueller held positions of increasing responsibility in engineering and management for Unocal throughout North America and Southeast Asia.

Lehman E. Newton, III. Mr. Newton joined the Company in December 2006 as General Manager for the

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Midland, Texas office, was appointed Vice President and Regional Manager of the Permian region in June 2007, and was appointed Senior Vice President and Regional Manager in May 2010. Mr. Newton has over 33 years of experience in the energy industry. From November 2005 to November 2006, Mr. Newton served as Project Manager for one of Chevron's largest Lower 48 projects. Mr. Newton joined Pure Resources in February 2003 as the Business Development Manager and worked in that capacity until October 2005. Mr. Newton was a founding partner in Westwin Energy, an independent Permian Basin exploration and production company, from June 2000 to January 2003. Prior to that, Mr. Newton spent 21 years with ARCO in various engineering, operations and management roles, including as Asset Manager, ARCO's East Texas operations, Vice President, Business Development, ARCO Permian, and Vice President of Operations and Development, ARCO Permian.

Paul M. Veatch. Mr. Veatch is a Senior Vice President and Regional Manager of the Company. He manages our Mid-Continent Region. Mr. Veatch joined the Company in April 2001 as Regional A & D Engineer. He served as the Company's Vice President - General Manager, ArkLaTex from August 2004 to March 2006, and Manager of Engineering for the ArkLaTex region from April 2003 to August 2004. Mr. Veatch has over 21 years of experience in the energy industry.

Mark T. Solomon. Mr. Solomon was appointed Vice President - Controller and Assistant Secretary of the Company in May 2011. He was appointed Controller of the Company in January 2007. Mr. Solomon served as the Company's Acting Principal Financial Officer from April 2008, to September 2008, which was during the period of time that the Company's Chief Financial Officer position was vacant. Mr. Solomon joined the Company in 1996. He served as Financial Reporting Manager from February 1999 to September 2002, Assistant Vice President - Financial Reporting from September 2002 to May 2006 and Assistant Vice President - Assistant Controller from May 2006 to January 2007. Prior to joining the Company, Mr. Solomon was an auditor with Ernst & Young. Mr. Solomon has over 15 years of experience in the energy industry.

Dennis A. Zubieta. Mr. Zubieta was appointed Vice President - Engineering and Evaluation of the Company in August 2008. Mr. Zubieta joined the Company in June 2000 as Corporate A&D Engineer, assumed the role of Reservoir Engineer in February 2003, and was appointed Reservoir Engineering Manager in August 2005. Mr. Zubieta was employed by Burlington Resources from June 1988 to May 2000 in various operations and reservoir engineering capacities. Mr. Zubieta has over 24 years of experience in the energy industry.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the information provided under the captions, Executive Compensation and Director Compensation in SM Energy's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from December 31, 2011.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item concerning security ownership of certain beneficial owners and management is incorporated by reference to the information provided under the caption Security Ownership of Certain Beneficial Owners and Management in SM Energy's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from December 31, 2011.

Securities Authorized for Issuance Under Equity Compensation Plans. SM Energy has the Equity Plan under which options and shares of SM Energy common stock are authorized for grant or issuance as compensation to eligible employees, consultants, and members of the Board of Directors. Our stockholders have approved this plan. See Note 7 – Compensation Plans included in Part II, Item 8 of this report for further information about the material terms of our equity compensation plans. The following table is a summary of the shares of common stock authorized for issuance under the equity compensation plans as of December 31, 2011:

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Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Equity Incentive Compensation Plan			
Stock options and incentive stock options (1)	508,214	$ 13.86	
Restricted stock (1)(3)	308,877	N/A	
Performance share units (1)(3)(4)	1,232,225	N/A	
Total for Equity Incentive Compensation Plan	2,049,316	$ 13.86	2,708,822
Employee Stock Purchase Plan (2)	-	-	1,373,969
Equity compensation plans not approved by security holders	-	-	-
Total for all plans	2,049,316	$ 13.86	4,082,791

(1) In May 2006, the stockholders approved the Equity Plan to authorize the issuance of restricted stock, restricted stock units, non-qualified stock options, incentive stock options, stock appreciation rights, performance shares, performance units, and stock-based awards to key employees, consultants, and members of the Board of Directors of SM Energy or any affiliate of SM Energy. The Equity Plan serves as the successor to the St. Mary Land & Exploration Company Stock Option Plan, the St. Mary Land & Exploration Company Incentive Stock Option Plan, the SM Energy Company Restricted Stock Plan, and the SM Energy Company Non-Employee Director Stock Compensation Plan (collectively referred to as the "Predecessor Plans"). All grants of equity are now made under the Equity Plan, and no further grants will be made under the Predecessor Plans. Each outstanding award under a Predecessor Plan immediately prior to the effective date of the Equity Plan continues to be governed solely by the terms and conditions of the instruments evidencing such grants or issuances. Our Board of Directors approved amendments to the Equity Plan in 2009 and 2010 and each amended plan was approved by stockholders at the respective annual stockholders' meetings. The awards granted in 2011, 2010, and 2009 under the Equity Plan were 386,802, 540,774, and 1,016,931, respectively.

(2) Under the SM Energy Company ESPP, eligible employees may purchase shares of our common stock through payroll deductions of up to 15 percent of their eligible compensation. The purchase price of the stock is 85 percent of the lower of the fair market value of the stock on the first or last day of the six-month offering period, and shares issued under the ESPP as of December 31, 2011, have no minimum restriction period. The ESPP is intended to qualify under Section 423 of the Internal Revenue Code. Shares issued under the ESPP totaled 41,358, 52,948, and 86,308 in 2011, 2010, and 2009, respectively.

(3) RSUs and PSUs do not have exercise prices associated with them, but rather a weighted-average per share fair value which is presented in order to provide additional information regarding the potential dilutive effect of the awards. The weighted-average grant date per share fair value for the outstanding RSUs and PSUs was $44.33 and $52.38, respectively. Please refer to Note 7 - Compensation Plan for additional discussion.

(4) The number of awards vested assumes a one multiplier. The final number of shares issued may vary depending on the ending three-year multiplier, which ranges from zero to two.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the information provided under the caption Certain Relationships and Related Transactions, and Corporate Governance, in SM Energy's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from December 31, 2011.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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The information required by this Item is incorporated by reference to the information provided under the caption Independent Registered Public Accounting Firm and Audit Committee Preapproval Policy and Procedures in SM Energy's definitive proxy statement for the 2012 annual meeting of stockholders to be filed within 120 days from December 31, 2011.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statements and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

Exhibit Number	Description
2.1	Purchase and Sale Agreement dated December 17, 2009 and effective as of November 1, 2009, between Legacy Reserves Operating LP and St. Mary Land & Exploration Company (filed as Exhibit 2.5 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference)
2.2	Purchase and Sale Agreement dated January 7, 2010 and effective as of November 1, 2009, between Sequel Energy Partners LP, Bakken Energy Partners, LLC, Three Forks Energy Partners, LLC and St. Mary Land & Exploration Company (filed as Exhibit 2.6 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2009 and incorporated herein by reference)
2.3	Purchase and Sale Agreement dated June 9, 2011, among SM Energy Company, Statoil Texas Onshore Properties LLC, and Tailsman Energy USA Inc. (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 and incorporated herein by reference)
2.4	Acquisition and Development Agreement dated June 29, 2011 between SM Energy Company and Mitsui E&P Texas LP (filed as Exhibit 2.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 and incorporated herein by reference)
2.5	First Amendment to Acquisition and Development Agreement dated October 13, 2011 between SM Energy Company and Mitsui E&P Texas (filed as Exhibit 2.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 and incorporated herein by reference)
3.1	Restated Certificate of Incorporation of SM Energy Company, as amended through June 1, 2010 (filed as Exhibit 3.1 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
3.2	Restated By-Laws of SM Energy Company amended effective as of June 1, 2010 (filed as Exhibit 3.2 to the registrant’s Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)
4.1	Indenture related to the 3.50% Senior Convertible Notes due 2027, dated as of April 4, 2007, between St. Mary Land & Exploration Company and Wells Fargo Bank, National Association, as trustee (including the form of 3.50% Senior Convertible Note due 2027) (filed as Exhibit 4.1 to the registrant’s Current Report on Form 8-K filed on April 4, 2007 and incorporated herein by reference)

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4.2	Registration Rights Agreement, dated as of April 4, 2007, among St. Mary Land & Exploration Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wachovia Capital Markets, LLC, for themselves and as representatives of the Initial Purchasers (filed Exhibit 4.2 to the registrant’s Current Report on Form 8-K filed on April 4, 2007, and incorporated herein by reference)
4.3	Indenture related to the 6.625% Senior Notes due 2019, dated as of February 7, 2011, by and between SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant’s Current Report on Form 8-K filed on February 10, 2011, and incorporated herein by reference)
4.4	Registration Rights Agreement, dated as of February 7, 2011, by and among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC, as representatives of the several initial purchasers (filed as Exhibit 4.2 to the registrant’s Current Report on Form 8-K filed on February 10, 2011, and incorporated herein by reference)
4.5	Indenture related to the 6.50% Senior Notes due 2021, dated as of November 8, 2011, by and among SM Energy Company, as issuer, and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to the registrant's Current Report on Form 8-K filed on November 10, 2011, and incorporated herein by reference)
4.6	Registration Rights Agreement, dated as of November 8, 2011, by and among SM Energy Company and Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and J.P. Morgan Securities LLC, as representatives of several purchasers (filed as Exhibit 4.2 to the registrant's Current Report on Form 8-K filed on November 10, 2011, and incorporated herein by reference)
10.1†	Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.1 to the registrant’s Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.2†	Incentive Stock Option Plan, as Amended on May 22, 2003 (filed as Exhibit 99.2 to the registrant’s Registration Statement on Form S-8 (Registration No. 333-106438) and incorporated herein by reference)
10.3†	Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference)
10.4†	Form of Amendment to Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.9 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2005 and incorporated herein by reference)
10.5†	Employment Agreement of A.J. Best dated May 1, 2006 (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on May 4, 2006 and incorporated herein by reference)
10.6†	Form of Performance Share Award Agreement (filed as Exhibit 10.4 to the registrant’s Quarterly Report on Form 10-Q filed on August 5, 2008 and incorporated herein by reference)
10.7†	Form of Performance Share Award Notice (filed as Exhibit 10.5 to the registrant’s Quarterly Report on Form 10-Q filed on August 5, 2008 and incorporated herein by reference)
10.8	Supplement and Amendment to Deed of Trust, Mortgage, Line of Credit Mortgage, Assignment, Security Agreement, Fixture Filing and Financing Statement for the benefit of Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.2 to the registrant’s Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.9	Deed of Trust to Wachovia Bank, National Association, as Administrative Agent, dated effective as of April 14, 2009 (filed as Exhibit 10.3 to the registrant’s Current Report on Form 8-K filed on April 20, 2009, and incorporated herein by reference)
10.10†	Equity Incentive Compensation Plan as Amended and Restated as of March 26, 2009 (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on May 27, 2009, and incorporated herein by reference)

10.11†	Equity Incentive Compensation Plan As Amended and Restated as of April 1, 2010 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on June 2, 2010, and incorporated herein by reference)

10.12s	SM Energy Company Equity Incentive Compensation Plan, As Amended as of July 30, 2010 (filed as Exhibit 10.7 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.13†	Form of Performance Share and Restricted Stock Unit Award Agreement (filed as Exhibit 10.5 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and incorporated herein by reference)
10.14†	Form of Performance Share and Restricted Stock Unit Award Notice (filed as Exhibit 10.6 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, and incorporated herein by reference)
10.15†	Third Amendment to Employee Stock Purchase Plan dated September 23, 2009 (filed as Exhibit 10.3 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, and incorporated herein by reference)
10.16†	Fourth Amendment to Employee Stock Purchase Plan dated December 29, 2009 (filed as Exhibit 10.46 to the registrant’s Annual Report on Form 10-K for the year ended December 31, 2009, and incorporated herein by reference)
10.17s	Employee Stock Purchase Plan, As Amended and Restated as of July 30, 2010 (filed as Exhibit 10.4 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.18	Carry and Earning Agreement between St. Mary Land & Exploration Company and Encana Oil & Gas (USA) Inc. executed as of April 29, 2010 (filed as Exhibit 10.2 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.19†	Form of Performance Share and Restricted Stock Unit Award Agreement as of July 1, 2010 (filed as Exhibit 10.3 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.20†	Form of Performance Share and Restricted Stock Unit Award Notice as of July 1, 2010 (filed as Exhibit 10.4 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.21†	Form of Non-Employee Director Restricted Stock Award Agreement as of May 27, 2010 (filed as Exhibit 10.5 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 and incorporated herein by reference)
10.22***	Gas Services Agreement effective as of July 1, 2010 between SM Energy Company and Eagle Ford Gathering LLC (filed as Exhibit 10.3 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.23s	Cash Bonus Plan, As Amended on July 30, 2010 (filed as Exhibit 10.5 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.24s	Net Profits Interest Bonus Plan, As Amended by the Board of Directors on July 30, 2010 (filed as Exhibit 10.6 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.25s	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan, As Amended as of July 30, 2010 (filed as Exhibit 10.8 to the registrant’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 and incorporated herein by reference)
10.26†	Form of Amendment to Form of Change of Control Executive Severance Agreement (filed as Exhibit 10.1 to the registrant’s Current Report on Form 8-K filed on December 29, 2010, and incorporated herein by reference)
10.27†	Amendment to A.J. Best Employment Agreement dated December 31, 2010 (filed as Exhibit 10.28 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.28	Purchase Agreement, dated January 31, 2011, among SM Energy Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Wells Fargo Securities, LLC, as representatives of the

	Initial Purchasers named therein (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on February 1, 2011, and incorporated herein by reference)
10.29	Pension Plan for Employees of SM Energy Company as Amended and Restated as of January 1, 2010 (filed as Exhibit 10.30 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)

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10.30+	SM Energy Company Non-Qualified Unfunded Supplemental Retirement Plan as Amended as of November 9, 2010 (filed as Exhibit 10.31 to the registrant's Annual Report on Form 10-K filed for the year ended December 31, 2010, and incorporated herein by reference)
10.31*†	Summary of Compensation Arrangements for Non-Employee Directors
10.32	Fourth Amended and Restated Credit Agreement dated May 27, 2011 among SM Energy Company, Wells Fargo Bank, National Association, as Administrative Agent, and the Lenders party thereto (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.33	Gas Gathering Agreement dated May 31, 2011 between Regency Field Services LLC and SM Energy Company (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.34	Gathering and Natural Gas Services Agreement effective as of April 1, 2011 between SM Energy Company and ETC Texas Pipeline, Ltd. (filed as Exhibit 10.3 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.35	Gas Processing Agreement effective as of April 1, 2011 between ETC Texas Pipeline, Ltd. and SM Energy Company (filed as Exhibit 10.4 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.36†	Employee Stock Purchase Plan, As Amended and Restated as of June 10, 2011 (filed as Exhibit 10.5 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.37†	Form of Performance Stock Unit Award Agreement as of July 1, 2011 (filed as Exhibit 10.6 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.38†	Form of Restricted Stock Unit Award Agreement as of July 1, 2011 (filed as Exhibit 10.7 to the registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, and incorporated herein by reference)
10.39†	Form of Performance Stock Unit Award Agreement as of September 6, 2011 (filed as Exhibit 10.1 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, and incorporated herein by reference)
10.40†	Form of Restricted Stock Unit Award Agreement as of September 6, 2011 (filed as Exhibit 10.2 to the registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, and incorporated herein by reference)
10.41*	Amendment No. 1 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2011
10.42*	Amendment No. 2 to the Pension Plan for Employees of SM Energy Company amended as of January 1, 2012
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	Subsidiaries of Registrant
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Ryder Scott Company L.P.
24.1*	Power of Attorney
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1**	Certification pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Ryder Scott Audit Letter
101.INS****	XBRL Instance Document
101.SCH****	XBRL Schema Document
101.CAL****	XBRL Calculation Linkbase Document

101.LAB**** XBRL Label Linkbase Document

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101.PRE****	XBRL Presentation Linkbase Document
101.DEF****	XBRL Taxonomy Extension Definition Linkbase Document

* Filed with this Form 10-K

** Furnished with this Form 10-K

*** Certain portions of this exhibit have been redacted and are subject to a confidential treatment order granted by the Securities and Exchange Commission pursuant to Rule 24b-2 under the Securities Exchange Act of 1934.

**** Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

† Exhibit constitutes a management contract or compensatory plan or agreement.

s Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on July 30, 2010 primarily to reflect the recent change in the name of the registrant from St. Mary Land & Exploration Company to SM Energy Company. There were no material changes to the substantive terms and conditions in this document.

\+ Exhibit constitutes a management contract or compensatory plan or agreement. This document was amended on November 9, 2010, in order to make technical revisions to ensure compliance with Section 409A of the Internal Revenue Code. There were no material changes to the substantive terms and conditions in this document.

(c) Financial Statement Schedules. See Item 15(a) above.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SM ENERGY COMPANY
(Registrant)

Date: February 23, 2012	By:	/s/ ANTHONY J. BEST Anthony J. Best President and Chief Executive Officer

GENERAL POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints each of Anthony J. Best and A. Wade Pursell his or her true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, and each with full power to act alone, for the undersigned and in his or her name, place and stead, in any and all capacities, to sign any amendments to this Annual Report on Form 10-K for the fiscal year ended December 31, 2011, and to file the same, with exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, hereby ratifying and confirming all that each of said attorney-in-fact, or his substitute or substitutes, may do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ANTHONY J. BEST Anthony J. Best	President and Chief Executive Officer	February 23, 2012
/s/ A. WADE PURSELL A. Wade Pursell	Executive Vice President and Chief Financial Officer	February 23, 2012
/s/ MARK T. SOLOMON Mark T. Solomon	Vice President and Controller	February 23, 2012

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Signature	Title	Date
/s/ WILLIAM D. SULLIVAN William D. Sullivan	Chairman of the Board of Directors	February 23, 2012
/s/ BARBARA M. BAUMANN Barbara M. Baumann	Director	February 23, 2012
/s/ LARRY W. BICKLE Larry W. Bickle	Director	February 23, 2012
/s/ STEPHEN R. BRAND Stephen R. Brand	Director	February 23, 2012
/s/ WILLIAM J. GARDINER William J. Gardiner	Director	February 23, 2012
/s/ JULIO M. QUINTANA Julio M. Quintana	Director	February 23, 2012
/s/ JOHN M. SEIDL John M. Seidl	Director	February 23, 2012