UTICA SHALE PREMIER ACREAGE GROWTH

STRONG FUNDAMENTALS EXECUTION

GULFPORT ENERGY CORPORATION

CASH FLOW RESERVE GROWTH EVOLVING

DATA DRIVEN INNOVATIVE CONSISTENCY

TRANSFORMATIONAL EFFICIENCIES

2013 ANNUAL REPORT

ABOUT GULFPORT

Gulfport Energy is an Oklahoma City-based independent oil and natural gas exploration and production company with its principal producing properties located in the Utica Shale of Eastern Ohio and along the Louisiana Gulf Coast. In addition, Gulfport holds a sizeable acreage position in the Alberta Oil Sands in Canada through its 24.9% interest in Grizzly Oil Sands ULC and has an equity interest in Diamondback Energy, Inc., a NASDAQ Global Select Market listed company.

DEAR FELLOW STOCKHOLDERS

2013 was a year of transformation for Gulfport.

2013 was a defining year for Gulfport, with several key accomplishments as we made great strides in the development of the Utica Shale and continued to see success from our historical Southern Louisiana assets. We ended 2013 with record company production of nearly 28,000 barrels of oil equivalent per day ("boepd"), which represented a 300% growth over our 2012 exit rate. In 2013, we achieved strong operating and financial results which included:

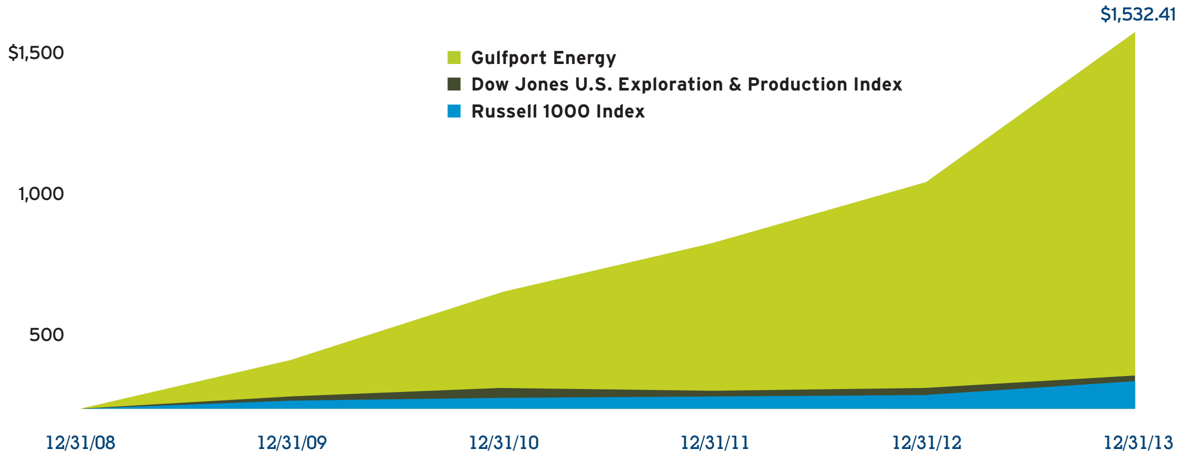
- Total yearly net production of 4.12 million barrels of oil equivalent.
- Oil and gas revenues of $262.2 million.
- Net income of $153.2 million, or $1.97 per fully diluted share.
- Total proved reserves of 38.43 million barrels of oil equivalent at 2013 year end.

Since 2008, Gulfport has grown from producing approximately 5,000 boepd to nearly 28,000 boepd at the end of 2013 and our stock has appreciated over 1,000%. Gulfport's strategy of identifying large banks of resource in place and applying advanced technologies to extract the resource has paid dividends and we continue to deploy this strategy as we develop our portfolio of assets in diverse geological locations, each of which carries a different set of potential rewards for the company and its stockholders.

IN THE CORE OF THE UTICA SHALE

During 2013, Gulfport continued to actively develop its position in the emerging Utica Shale of Eastern Ohio. We began the year with 106,000 net acres and through the acquisition of our partners' interests and on-the-ground leasing efforts have grown our overall position to over 165,000 net acres, increasing our drilling inventory to approximately 1,050 locations at statutory 1,000 foot spacing, solidifying our position as a leading player in the southern portion of the play. Gulfport added six horizontal drilling rigs to its program in 2013, exiting the year with a seven rig fleet drilling on our acreage. In 2013, we spud 52 gross wells in the play, making Gulfport the second most active driller in the state of Ohio. During 2013, we continued to focus our efforts on managing our costs while drilling the most optimal wells possible.

5 Year Performance



The graph above compares the performance of our common stock to the Russell 1000 Index and the Dow Jones U.S. Exploration & Production Index for the past five years. The graph assumes an investment of $100 on December 31, 2008 and the reinvestment of all dividends. The graph shows the value of the investment at the end of each year.

With this in mind, we added many key personnel during 2013 to help lead our operations in Ohio and execute on our planned activities. These additions, along with our existing staff, contributed to our success in 2013 and will also allow the company to excel in 2014 and beyond.

In 2013, we remained focused on building out our midstream and takeaway platform to support our production plans for the near and long term. As with any new emerging play, lack of physical infrastructure is always a concern. By year end 2013, the infrastructure had vastly improved which allowed Gulfport to continue to expand its drilling program without the concern that our locations would not have adequate infrastructure in place. In terms of takeaway, by recognizing early that firm transport was going to be the key to success for producers in the Utica, we were a first mover and successfully locked in 500 million cubic feet per day of residue gas takeaway out of the basin at attractive rates and we will continue to secure additional firm transport and sales agreements as our production base grows. Gulfport was strategic when selecting to participate in midstream and takeaway projects and, with the majority of the infrastructure in place and the ability to capture attractive firm agreements, we believe we are well positioned in 2014 to deliver and sell our product.

CANADIAN OIL SANDS ACHIEVES FIRST STEAM

In the Canadian Oil Sands, through Gulfport's 25% interest in Grizzly Oil Sands, ULC ("Grizzly"), we were pleased to announce that Grizzly completed construction of its steam assisted gravity drainage ("SAGD") facility at its Algar Lake property and commenced steam generation during December 2013. First steam was a key milestone for Grizzly as it marks the start-up of its first SAGD facility in the oil sands. The first phase of Algar Lake is expected to ramp to its peak capacity of approximately 5,500 barrels of bitumen per day in the next twelve to eighteen months and the Grizzly team is already encouraged by the project's progress to date. Grizzly had an active winter drilling season, completing a 29 well delineation drilling program at its May River area and subsequently filing a development application for an initial 12,000 barrel per day project at May River in late 2013.

During 2013, with first steam and production near term, Grizzly remained focused on developing a strategic marketing strategy that allowed it to secure attractive prices for its bitumen by moving its product to the US Gulf Coast. Grizzly began construction of a 15,000 barrel per day rail transloading facility at its Windell Terminal in Conklin, Alberta in late 2013. It has since commenced operations and the first load of dilbit from Algar Lake was hauled by truck to the terminal for sales to the Gulf Coast. Grizzly continues to build out this robust infrastructure and recently filed the development permits for its Paulina Terminal along the lower Mississippi River. To support the rail movement of its product, Grizzly focused on ensuring access to key markets at attractive prices which are expected to ultimately increase returns and project economics.

CONTINUED SUCCESS IN SOUTHERN LOUISIANA

Our Southern Louisiana assets continued to provide a steady production base as we drilled a total of 40 wells during 2013 with a 98% success rate. Our West Cote Blanche Bay and Hackberry fields produced an average of 5,571 boepd in 2013 and continue to produce at similar levels today with our current rig activity in the area. Southern Louisiana production benefits from premium Louisiana Sweet pricing, which provides additional uplift to already attractive returns and allows the company to deploy excess cash flow into the Utica development program.

ADDING VALUE THROUGH EQUITY OWNERSHIP

In October 2012, Gulfport contributed its oil and gas interests in the Permian Basin to Diamondback Energy, Inc. ("Diamondback") in connection with Diamondback's initial public offering ("IPO") and, as of December 31, 2013, Gulfport held approximately 3.4 million shares of Diamondback common stock valued at over $179 million. At the end of 2013, Diamondback's stock had increased 202% since the IPO and we continue to be pleased with our investment in that company and the value it has provided for our stockholders.

LOOKING AHEAD TO 2014

In 2013, Gulfport faced many challenges that come alongside operating in a new emerging play, but we believe the accomplishments highlighted above have positioned the company for success in 2014 and beyond. Our planned 2014 activities have Gulfport poised for another year of record production growth for the company and top-tier growth compared to our peers in the industry.

We continue to be committed to establishing a culture of execution and are proud of the Gulfport team as its continued dedication has helped Gulfport become a leading producer in the southern portion of the Utica Shale. We are fortunate to have the support of our employees, Board of Directors, business partners and fellow stockholders, and we thank you for your continued support and confidence in Gulfport Energy.

We look forward to 2014 and remain confident that we have the right people and strategy in place to consistently deliver profitable growth.

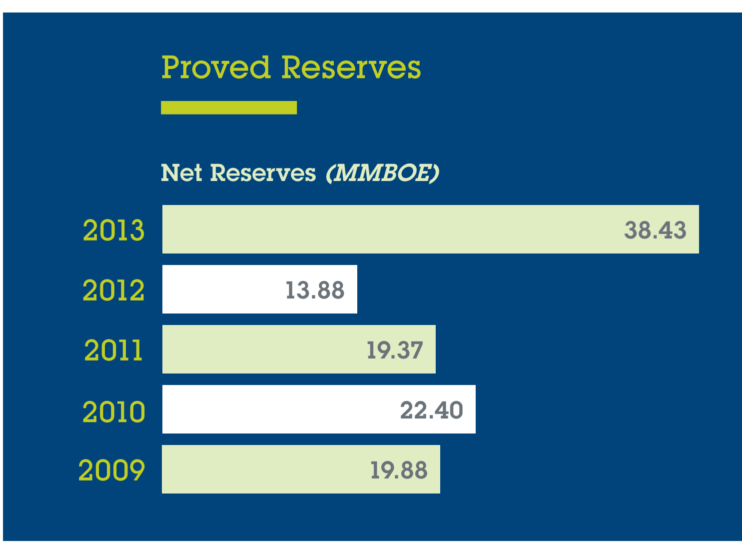
Respectfully,

Michael G. Moore

Michael G. Moore
Chief Executive Officer & President

David L. Houston

David L. Houston
Chairman of the Board



Total Production

Daily Net Production ***(BOEPD)***

2013	11,283
2012	7,029
2011	6,392
2010	5,413
2009	4,596

Daily Net Production ***(BOEPD)***

4Q 2013	16,668
3Q 2013	12,976
2Q 2013	8,959
1Q 2013	6,395

ASSET AREAS

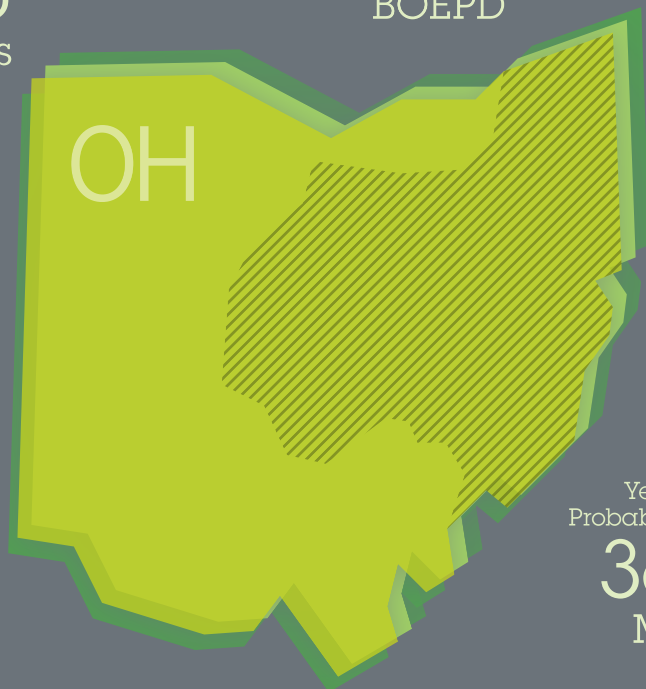
UTICA

Our Utica Shale position is located in the Appalachian Basin in Southeastern Ohio.

- Gross Wells Spud in 2013: **52**
- Exited 2013 running **7 rigs**
- Increasing access to superior residue gas markets by securing over **500 million cubic foot** of takeaway through firm agreements.

Year End 2013 Leasehold Position:
143,000
Net Acres

4th Quarter 2013 Production:
10,701
BOEPD



Year End 2013 Proved Reserves:
32.35
MMBOE

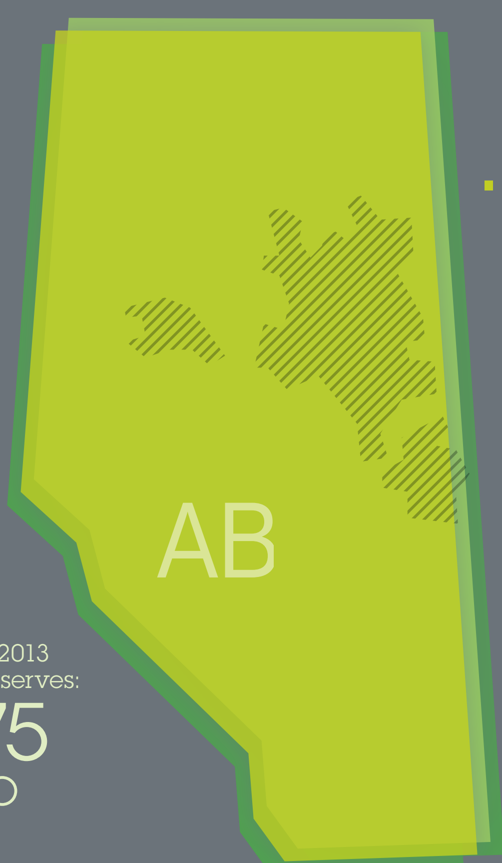
Year End 2013 Probable Reserves:
36.46
MMBOE

CANADIAN OIL SANDS

Our Canadian Oil Sands fields are operated through a 25% interest in Grizzly Oil Sands, ULC.

- Grizzly achieved first steam at its first SAGD facility at Algar Lake during the 4th quarter of 2013.

Leasehold Position:
207,000
Net Acres



Year End 2013 Probable Reserves:
51.00
MMBO

Year End 2013 Proved Reserves:
16.75
MMBO

Year End 2013 Recoverable Resource:
778.00
MMBO

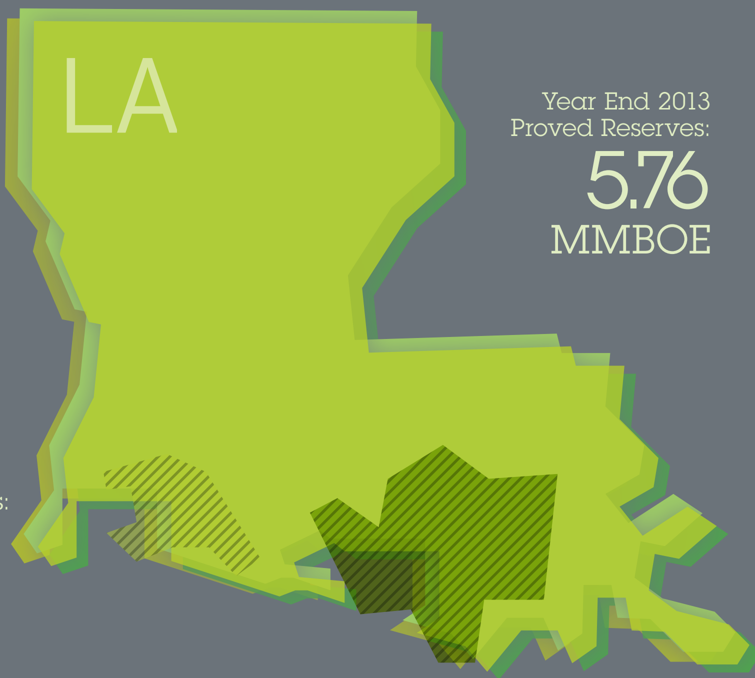
Year End 2013
Leasehold Position:
11,400
Net Acres

4th Quarter
2013 Production:
5,888
BOEPD

SOUTHERN LOUISIANA

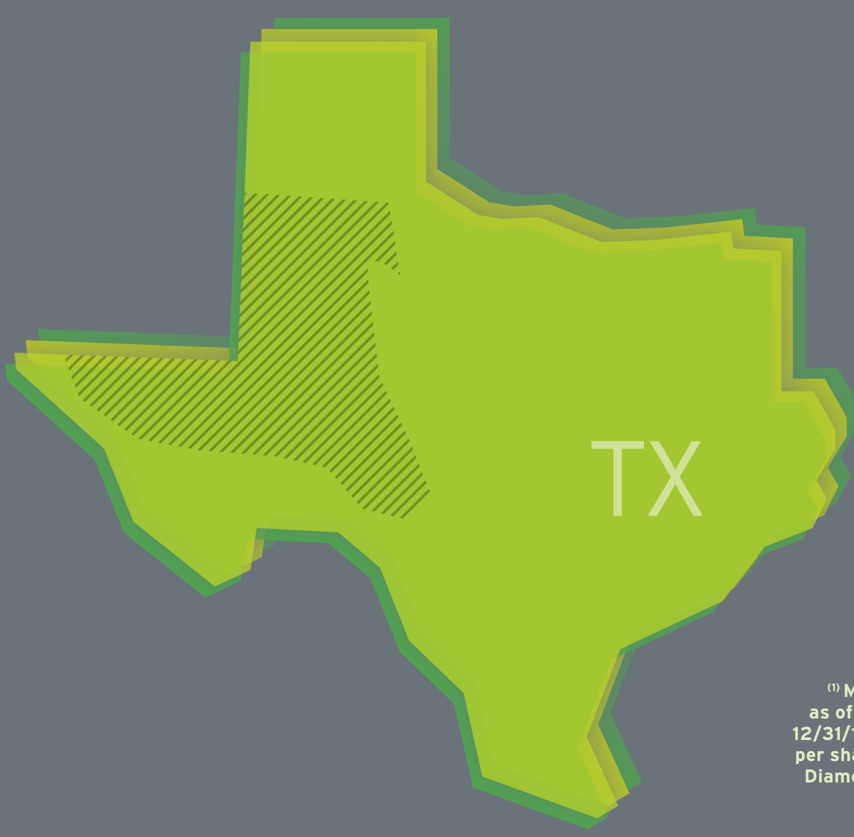
Our Southern Louisiana operations are located in the West Cote Blanche Bay and Hackberry fields.

- Gross Wells Spud in 2013: **40**



Year End 2013
Proved Reserves:
5.76
MMBOE

Year End 2013
Probable Reserves:
7.84
MMBOE



PERMIAN

Our interest in the Permian Basin in West Texas is by the way of 3.4 million shares of common stock in Diamondback Energy, Inc., a NASDAQ Global Select Market listed company.

Market Value
12/31/2013:
$179
Million[1]

[1] Market value calculated as of the close of market on 12/31/13 at a price of $52.88 per share using 3.4 million of Diamondback Energy's total shares outstanding.

PREMIER ACREAGE VALUE CREATION

STRONG FUNDAMENTALS EXECUTION

UTICA SHALE

CASH FLOW RESERVE GROWTH EVOLVING

CONSISTENCY RESOURCE DEVELOPMENT

GEOLOGICALLY FOCUSED TECHNICAL LIMITS

The phenomenal success we have achieved in the Utica Shale has solidified our position as a leading player in the prolific Appalachian Basin.

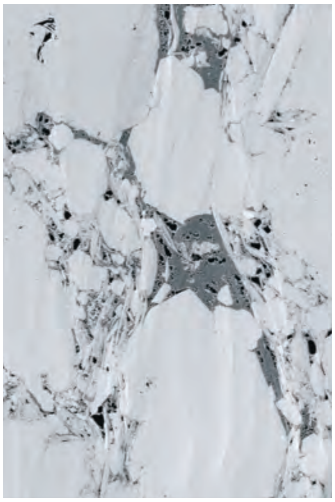
Unique geology characterizes one of North America's hottest plays.

The Utica Shale is located in the Appalachian Basin of the United States and Canada. The Utica Shale is a rock unit comprised of organic rich calcareous black shale that was deposited about 440 million to 460 million years ago during the Late Ordovician period. It overlies the Trenton Limestone and is located a few thousand feet below the Marcellus Shale, which is estimated to be the largest exploration play in the Eastern United States.

The application of horizontal drilling, combined with multistaged hydraulic fracturing to create permeable flow paths from wellbores into shale units, has resulted in increased drilling activity and production in the Devonian-age Marcellus Shale in the Appalachian Basin states of Pennsylvania, West Virginia, Southern New York and Eastern Ohio. This proven technology has application in other shale units, such as the Ordovician-age Utica Shale, which extends across much of the Appalachian Basin region.

The potential source rock portion of the Utica Shale underlies portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia in the United States and is also present beneath parts of Lake Ontario, Lake Erie and part of Ontario, Canada. Throughout the potential source rock area, the Utica Shale ranges in thickness from less than 100 feet to over 500 feet. Over the rock unit as a whole, there is a general thinning from east to west.

The Utica Shale is significantly deeper than the Marcellus Shale. In some parts of Pennsylvania; the Utica Shale is estimated to be over two miles below sea level and up to 7,000 feet below the Marcellus Shale. However, the depth of the Utica Shale decreases to the west into Ohio and to the northwest under the Great Lakes and into Canada to less than 2,000 feet below sea level.



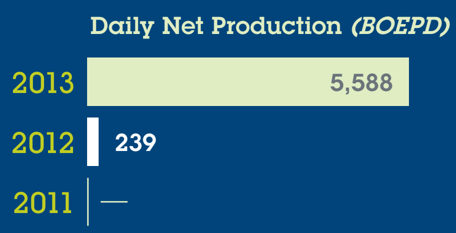
Ion-milled Scanned Electron Microscopy (SEM) images show extensive organic porosity, which creates superior permeability in the rock.

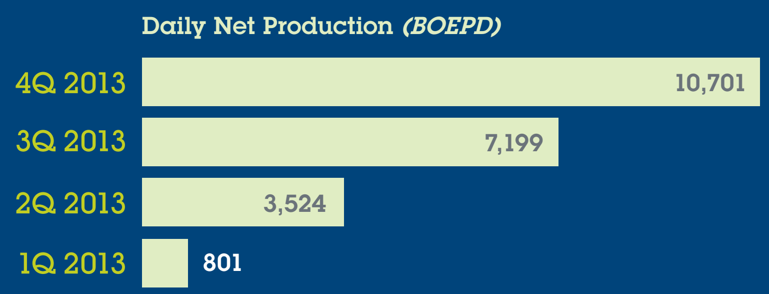
Early Mover Advantage

165,430

net acres approximately under lease in the Utica as of 2/26/14.

Utica Production





FINANCIAL HIGHLIGHTS

	2013	2012	2011
PRODUCTION			
Oil and Gas Volumes			
Oil - MBBLS	**2,317**	2,323	2,128
Natural Gas - MMCF	**8,891**	1,108	878
Natural Gas Liquids - MGALS	**13,416**	2,714	2,468
MBOE	**4,118**	2,573	2,333
BOEPD	**11,283**	7,029	6,392
INCOME STATEMENT			
Revenues *(In thousands)*			
Oil	**$ 224,129**	$ 242,708	$ 222,025
Natural Gas	**21,015**	3,225	3,838
Natural Gas Liquids	**17,081**	2,668	3,090
Other income (expense)	**528**	325	301
Total	**$ 262,753**	$ 248,926	$ 229,254
Costs and Expenses *(Per BOE)*			
Lease operating expenses	**$ 6.48**	$ 9.45	$ 8.96
Production taxes	**$ 6.54**	$ 11.26	$ 11.17
Midstream transportation, processing and marketing	**$ 2.68**	$ 0.17	$ 0.12
Depreciation, depletion and amortization	**$ 28.87**	$ 35.27	$ 26.71
General and administrative	**$ 5.47**	$ 5.37	$ 3.46
Accretion	**$ 0.17**	$ 0.27	$ 0.29
Loss (gain) on sale of assets	**$ 0.12**	$ (2.84)	$ –
Financial Highlights *(In thousands, expect per share data)*			
Income from Operations	**$ 55,463**	$ 97,263	$ 110,964
Net Income	**$ 153,192**	$ 68,371	$ 108,422
Basic net income per share	**$ 1.98**	$ 1.22	$ 2.22
Basic Weighted Average Shares Outstanding	**77,376**	55,933	48,755
Diluted Weighted Average Shares Outstanding	**77,862**	56,417	49,207
Total assets	**$ 2,693,136**	$ 1,578,368	$ 691,158
Total debt, including current maturity	**$ 299,187**	$ 299,038	$ 2,283
Stockholders' equity	**$ 2,050,238**	$ 1,126,408	$ 632,350
RESERVES			
Proved Reserves			
Oil *(MMBBL)*	**14.02**	8.25	16.75
Natural Gas *(BCF)*	**146.44**	33.77	15.73
Oil Equivalent *(MMBOE)*	**38.43**	13.88	19.37
Probable Reserves	**44.38**	26.27	21.92
Proved and Probable Reserves	**82.81**	40.15	41.29

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

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2013
OR

☐ **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 000-19514

Gulfport Energy Corporation
(Exact Name of Registrant As Specified in Its Charter)

Delaware	**73-1521290**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
14313 North May Avenue, Suite 100 Oklahoma City, Oklahoma	**73134**
(Address of Principal Executive Offices)	**(Zip Code)**

(405) 848-8807
(Registrant 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, par value $0.01 per share	**The NASDAQ Stock Market LLC**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☒ No ☐

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

Large Accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 28, 2013, based on the closing price of the common stock on the NASDAQ Global Select Market on June 28, 2013, the last business day of the registrant's most recently completed second fiscal quarter ($47.09 per share), was $3,651,716,766,540.00.

As of February 21, 2014, 85,217,533 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Gulfport Energy Corporation's Proxy Statement for the 2014 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

GULFPORT ENERGY CORPORATION
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FORWARD-LOOKING STATEMENTS

Our disclosure and analysis in this Form 10-K may include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements by terms such as "may," "will," "should," "could," "would," "expects," "plans," "anticipates," "intends," "believes," "estimates," "projects," "predicts," "potential" and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as estimated future net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements.

These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the "*Risk Factors*" and "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" sections and elsewhere in this Form 10-K. All forward-looking statements speak only as of the date of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

ITEM 1. BUSINESS

General

We are an independent oil and natural gas exploration and production company focused on the exploration, exploitation, acquisition and production of crude oil, natural gas liquids and natural gas in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, an equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and natural gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO, and interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

On February 26, 2014, we entered into an agreement to acquire approximately 8,200 additional net acres in the Utica Shale. See "- Recent Developments" below. As of February 27, 2014, after giving pro forma effect to the acquisition, we would have owned leasehold interests in approximately 167,700 gross (165,400 net) acres in the Utica Shale in Eastern Ohio. We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2013, had spud 66 wells, 38 of which were completed and are producing. In 2013, we spud 52 gross (39 net) wells, of which 24 were completed as producing wells, 11 were waiting on completion, one was non-productive, nine were waiting on horizontal rigs and seven were still being drilled as of December 31, 2013. As of February 14, 2014, we had spud six gross (five net) wells all of which were still drilling. In addition, 61 gross (3.5 net) wells were drilled by other operators on our Utica Shale acreage during 2012 and 2013.

We have seven rigs under contract on our Utica Shale acreage. We currently intend to drill 85 to 95 gross (64 to 71 net) wells on our Utica Shale acreage in 2014 for an estimated aggregate cost of $594.0 million to $634.0 million.

Aggregate net production from our Utica Shale acreage during the three months ended December 31, 2013 was approximately 984,528 net barrels of oil equivalent, or BOE, or 10,701 BOE per day, 68% of which was from natural gas and 32% of which was from oil and natural gas liquids, or NGLs. During January 2014, our average daily net production from the Utica Shale was approximately 15,897 BOE, 27% of which was from oil and NGLs and 73% of which was from natural gas.

In 2013, at our WCBB field, we recompleted 87 wells and drilled 22 wells. Of the 22 new wells drilled at WCBB in 2013, 21 were completed as producing wells and one was being drilled at year end. In the fourth quarter of 2013, production at WCBB was approximately 346,736 BOE, or an average of 3,769 BOE per day, 97% of which was from oil and 3% of which was from natural gas. During January 2014, our average net daily production at WCBB was approximately 3,158 BOE, 100% of which was from oil. During 2014, we currently anticipate drilling 22 to 24 wells at our WCBB field for an estimated aggregate cost of $42.0 million to $45.0 million.

In 2013, at our East Hackberry field, we recompleted 61 wells and drilled 16 wells. Of the 16 new wells drilled at East Hackberry during 2013, 13 were completed as producing wells, one was non-productive, one was waiting on completion and one was being drilled at year end. In the fourth quarter of 2013, net production at East Hackberry was approximately 188,536 BOE, or an average of 2,049 BOE per day, 90% of which was from oil and 10% of which was from natural gas. During January 2014, our average net daily production at East Hackberry was approximately 2,431 BOE, 93% of which was from oil and 7% of which was from natural gas. During 2014, we currently anticipate drilling ten to twelve wells for an estimated aggregate cost of $24.0 million to $26.0 million.

In 2013, at our West Hackberry field, we recompleted two wells and drilled two wells as of December 31, 2013. Of the two new wells drilled at West Hackberry during 2013, both were productive. In the fourth quarter of 2013, net production at West Hackberry was approximately 6,466 BOE, or an average of 70 BOE per day, 100% of which was from oil. During January 2014, our average net daily production at West Hackberry was approximately 110 BOE, 100% of which was from oil.

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Northwestern Colorado and, as of December 31, 2013, we held leases for approximately 7,481 net acres. During the year ended December 31, 2013, there were no wells spud on our Niobrara Formation acreage. In the fourth quarter of 2013, net production from our Niobrara Formation acreage was approximately 4,552 BOE, or an average of 49 BOE per day, 100% of which was from oil. During January 2014, our average net daily production from our Niobrara Formation acreage was approximately 55 BOE, 100% of which was from oil. During 2014, we currently do not anticipate drilling any wells in the Niobrara Formation.

As of December 31, 2013, we held approximately 864 net acres in the Bakken Formation of Western North Dakota and Eastern Montana with interests in 13 wells and overriding royalty interests in certain existing and future wells. In the fourth quarter of 2013, our net production from this acreage was approximately 2,412 BOE, or an average of 26 BOE per day, of which 90% was from oil and 10% was from NGLs. During January 2014, our average daily net production from our Bakken Formation acreage was approximately 93 BOE, of which 88% was from oil and 12% was from natural gas.

As of December 31, 2013, we owned approximately 7.2% of the outstanding common stock of Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and gas interests in October 2012 immediately prior to the Diamondback IPO. See Notes 4 and 5 to our consolidated financial statements included elsewhere in this report for additional information regarding our investment in Diamondback.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. As of December 31, 2013, Grizzly had approximately 830,000 net acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada and had drilled an aggregate of 255 core holes and six water supply test wells on ten separate lease blocks and conducted a number of seismic programs. Grizzly has three oil sands projects in various stages of development. At Grizzly's 11,300 barrel per day steam-assisted gravity drainage, or SAGD, oil sand project at Algar Lake, steam generation commenced and was circulating through the plant and well pad facilities by year-end 2013 and reservoir steam injection commenced in January 2014, with first production expected by the end of the first quarter of 2014. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. At May River, an initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. A 29 well delineation drilling program was completed in the first quarter of 2013 over the development application area and a 2D seismic program covering approximately 80 kilometers is currently underway to more fully define the development area. At the Thickwood thermal project, activities have included the completion of a 22 well core hole drilling program and the acquisition of 31 kilometers of seismic data. A development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. Grizzly has also entered into a memorandum of understanding that outlines the rate structure for a ten year agreement with Canadian National Railway Company, or CN, to transport its bitumen to the U.S. Gulf Coast via CN's rail network. Grizzly expects that this arrangement will provide consistent access to Brent-based pricing from Grizzly's Algar Lake project. Grizzly is developing a rail loadout facility in Conklin, Alberta, which we refer to as the Windell Terminal, and a rail to barge off-load facility on the lower Mississippi River, which we refer to as the Paulina Terminal. Construction of the 15,000 barrel per day truck to rail transloading Windell Terminal proximate to its May River lease, is expected to be completed and ready for operation by the end of the first quarter of 2014. In the U.S. Gulf Coast, Grizzly has begun engineering design work of the 40,000 barrel per day rail/barge Paulina terminal project located on the lower Mississippi River and has filed development permits.

We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC, or APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field.

We also own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. In March 2011, the second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. However, despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. In October 2013, Tatex III spud the TEW-K well, located to the south of the TEW-E well. The well tested gas at non-commercial rates. During drilling, the well flowed gas with rates as high as 20 MMcf per day of gas; however, no acceptable sustainable rate was established.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the first quarter of 2013, we participated in the formation of Stingray Energy Services LLC, or Stingray Energy, with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure Pumping LLC, or Stingray Pressure, Stingray Cementing LLC, or Stingray Cementing, and Stingray Logistics LLC, or Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk Midstream LLC, or Blackhawk, and Timber Wolf Terminals, LLC, or Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Windsor Midstream LLC, or Midstream which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison Drilling and Field Services LLC, or Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie Proppant LLC, or Muskie (formerly known as Muskie Holdings LLC), which is engaged in the processing and sale of hydraulic fracturing grade sand. See Note 5 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

As of December 31, 2013, we had 38.4 million barrels of oil equivalent, or MMBOE, of proved reserves with a present value of estimated future net revenues, discounted at 10%, or PV-10, of approximately $696.9 million and associated standardized measure of discounted future net cash flows of approximately $578.5 million, excluding reserves attributable to our interests in Diamondback, Grizzly, Tatex II and Tatex III. See "Item 2. *Properties-Proved Oil and Natural Gas Reserves*" for our definition of PV-10, a non-GAAP financial measure, and a reconciliation of our standardized measure of discounted future net cash flows to PV-10.

Recent Developments

On February 26, 2014, we entered into a binding letter of intent with Rhino Resources Partners LP, or Rhino, to acquire approximately 8,200 net acres in the Utica Shale of Eastern Ohio and approximately 1,000 BOEPD of production during January 2014 for a total purchase price of $185.0 million, subject to closing adjustments. These assets constitute all the rights, title and interest in leasehold and mineral interests covered by all oil and gas leases owned by Rhino in the Utica Shale in Eastern Ohio, together with all wells, production, data, equipment, contracts permits and privileges relating to the ownership of such properties. We are the operator of substantially all of this acreage. We plan to fund this acquisition from existing cash on hand. The acquisition is expected to close by the end of March 2014, however the transaction remains subject to completion of due diligence and other closing conditions, and there can be no assurance that the transaction will be completed.

Principal Oil and Natural Gas Properties

The following table presents certain information as of December 31, 2013 reflecting our net interest in our principal producing oil and natural gas properties in the Utica Shale in Eastern Ohio, along the Louisiana Gulf Coast, in the Niobrara Formation in Northwestern Colorado and in the Bakken Formation in Western North Dakota and Eastern Montana.

Field	NRI/WI (1)	Productive Wells (2)		Non-Productive Wells		Developed Acreage (3)		Proved Reserves			
								Gas	Oil	NGLs	Total
	Percentages	Gross	Net	Gross	Net	Gross	Net	MBOE	MBOE	MBOE	MBOE
Utica Shale (4)	51.61/63.9	38	24	1	1	10,627	8,694	23,983	2,696	5,674	32,353
West Cote Blanche Bay Field (5)	80.108/100	110	110	201	201	5,668	5,668	241	3,737	—	3,978
E. Hackberry Field (6)	80.309/100	47	47	86	86	3,931	3,931	142	1,170	—	1,312
W. Hackberry Field	83.333/100	4	4	19	19	1,192	1,192	—	470	—	470
Niobrara Formation	36.77/47.85	6	3	1	1	3,448	1,724	25	186	—	211
Bakken Formation (4)	2.16/1.795	13	0.3	—	—	1,862	163	13	86	—	99
Overrides/Royalty Non-operated	Various	266	0.45	2	0.06	—	—	4	1	1	6
Total		484	188.75	310	308.06	26,728	21,372	24,408	8,346	5,675	38,429

(1) Net Revenue Interest (NRI)/Working Interest (WI) for producing wells.
(2) Includes three gross and net wells at WCBB that are producing intermittently.

(3) Developed acres are acres spaced or assigned to productive wells. Approximately 13% of our acreage is developed acreage and has been held by production.
(4) Includes NRI/WI from wells that have been drilled or in which we have elected to participate.
(5) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(6) NRI shown is for producing wells.

Utica Shale (Eastern Ohio)

Location and Land

As of December 31, 2013, we had acquired leasehold interests in approximately 152,000 gross (143,000 net) acres in the Utica Shale in Eastern Ohio,

Area History

Based on the estimates published by the Ohio Department of Natural Resources, or ODNR, which were last updated in 2012, the Utica Shale has a recoverable potential of 1.3 billion to 5.5 billion barrels of oil and 3.8 to 15.7 trillion cubic feet of natural gas in Ohio alone. During 2012 and 2013, a number of oil and gas companies made significant investments in acquiring Utica Shale acreage in Eastern Ohio. As of February 9, 2013, the ODNR reported that in the Utica Shale in Ohio there were 65 producing horizontal wells, 236 horizontal wells that had been drilled but were not yet completed or connected to a pipeline, 15 horizontal wells that were being drilled and an additional 272 horizontal wells that had been permitted.

Geology

The Utica Shale is located in the Appalachian Basin of the United States and Canada. The Utica Shale is a rock unit comprised of organic-rich calcareous black shale that was deposited about 440 million to 460 million years ago during the Late Ordovician period. It overlies the Trenton Limestone and is located a few thousand feet below the Marcellus Shale, which is estimated to be the largest exploration play in the Eastern United States.

Recently, the application of horizontal drilling, combined with multistaged hydraulic fracturing to create permeable flow paths from wellbores into shale units, has resulted in increased drilling activity and production in the Devonian-age Marcellus Shale in the Appalachian Basin states of Pennsylvania, West Virginia, Southern New York and Eastern Ohio. This proven technology has potential for application in other shale units, such as the Ordovician-age Utica Shale, which extends across much of the Appalachian Basin region.

The Utica Shale is estimated to be thicker and more geographically extensive than the Marcellus Shale. The potential source rock portion of the Utica Shale underlies portions of Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, West Virginia and Virginia in the United States and is also present beneath parts of Lake Ontario, Lake Erie and Ontario, Canada. Throughout the potential source rock area, the Utica Shale ranges in thickness from less than 100 feet to over 500 feet. Over the rock unit as a whole, there is a general thinning from east to west.

The Utica Shale is also significantly deeper than the Marcellus Shale. In some parts of Pennsylvania, the Utica Shale is estimated to be over two miles below sea level and up to 7,000 feet below the Marcellus Shale. However, the depth of the Utica Shale decreases to the west into Ohio and to the northwest under the Great Lakes and into Canada to less than 2,000 feet below sea level.

The Utica Shale is estimated to have higher carbonate and lower clay mineral content than the Marcellus Shale. The difference in mineralogy generally produces a different response to hydraulic fracturing treatments. Based on early fracturing results in the Utica Shale, the hydraulic fracturing methods used in the Marcellus Shale are less productive when applied in the Utica Shale. However, drillers have improved the fracturing rates in other gas shales with similar carbonate content. For example, drillers have discovered methods to make the brittle carbonate zones fracture at higher rates than other gas shale rock units in the Eagle Ford Shale in Texas. Drillers are researching methods to make similar fracturing improvements in the Utica Shale.

Facilities

There are standard land oil and gas processing facilities in the Utica Shale. We will be required to build facilities located at well site pads inclusive of storage tank batteries, oil/gas/water separation equipment, vapor recovery units, line heaters, compression and applicable metering.

Recent and Future Activities

We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2013, had spud 66 wells, 38 of which were completed and are producing. In 2013, we spud 52 gross (39 net) wells, of which 24 were completed and are productive, 11 were waiting on completion, one was non-productive, nine were waiting on horizontal rigs and seven were still being drilled as of December 31, 2013. As of February 14, 2014, we had spud six gross (five net) wells during 2014 all of which were still drilling. In addition, 49 gross (2.6 net) wells were drilled by other operators on our Utica Shale acreage during 2013.

We have seven rigs under contract on our Utica Shale acreage. We currently intend to drill 85 to 95 gross (64 to 71 net) wells on our Utica Shale acreage in 2014.

Production Status

Aggregate net production from the Utica Shale during the three months ended December 31, 2013 was approximately 984,528 BOE, or 10,701 BOE per day, 68% of which was from natural gas and 32% of which was from oil and NGLs. From January 1, 2014 through January 31, 2014, our average daily net production from the Utica Shale was approximately 15,897 BOE, 27% of which was from oil and NGLs and 73% of which was from natural gas. The increase in January 2014 production is a result of our 2013 drilling activities.

West Cote Blanche Bay Field

Location and Land

The WCBB field is located approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. We own a 100% working interest (80.108% net revenue interest, or NRI), and are the operator, in depths above the base of the 13900 Sand which is located at 11,320 feet. In addition, we own a 40.40% non-operated working interest (29.95% NRI) in depths below the base of the 13900 Sand, which is operated by Chevron Corporation. Our leasehold interests at WCBB contain 5,668 gross acres.

Area History and Production

Texaco, now Chevron Corporation, drilled the discovery well in this field in 1940 based on a seismic and gravitational anomaly. WCBB was subsequently developed on an even 160-acre pattern for much of the remainder of the decade. Developmental drilling continued and reached its peak in the 1970s when over 300 wells were drilled in the field. Of the 1,047 wells drilled as of December 31, 2013, 949 were completed as producing wells. As a result, the field has a historic success rate of 91% for all wells drilled. From the date of our acquisition of WCBB in 1997 through December 31, 2013, we drilled 236 new wells, 215 of which were productive, for a 91% success rate. As of December 31, 2013, estimated field cumulative gross production was 195.3 MMBOE and 237.0 Bcf of gas. Of the 1,047 wells drilled in WCBB as of December 31, 2013, 107 were producing, 201 were shut-in, three were producing intermittently and five were being used as salt water disposal wells. The other 731 wells have been plugged and abandoned.

In 1991, Texaco conducted a 70 square mile 3-D seismic survey with 1,100 shot points per mile that processed out 100 fold. In 1993, an undershoot survey around the crest and production facilities was completed. We own the rights to the seismic data. In December 1999, we completed the reprocessing of the seismic data and our technical staff developed prospects from the data. The reprocessed data has enabled us to identify prospects in areas of the field that would have otherwise remained obscure. During the first half of 2005, we again reprocessed the seismic data using advanced seismic data processing.

Geology

WCBB overlies one of the largest salt dome structures on the Gulf Coast. The field is characterized by a piercement salt dome, which created traps from the Pleistocene through the Miocene formations. The relative movements affected deposition and created a complex system of fault traps. The compensating fault sets generally trend northwest to southeast and are intersected by sets having a major radial component. Later-stage movement caused extension over the dome and a large graben system (a downthrown area bounded by normal faults) was formed.

There are over 100 distinct sandstone reservoirs recognized throughout most of the field, and nearly 200 major and minor discrete intervals have been tested. Within the 1,047 wells that had been drilled in the field as of December 31, 2013, over 4,000 potential zones have been penetrated. These sands are highly porous and permeable reservoirs primarily with a strong water drive.

WCBB is a structurally and stratigraphically complex field. All of the proved undeveloped, or PUD, locations at WCBB are adjacent to faults and abut at least one fault. Our drilling programs are designed to penetrate each PUD trap with a new wellbore in a structurally optimum position, usually very close to the fault seal. The majority of these wells have been, and new wells drilled in connection with our drilling programs will be, directionally drilled using steering tools and downhole motors. The tolerance for error in getting near the fault is low, so the complex faulting does introduce the risk of crossing the fault before encountering the zone of interest, which could result in part or all of the zone being absent in the borehole. This, in turn, can result in lower than expected or no reserves for that zone. The new wellbores eliminate the mechanical risk associated with trying to produce the zone from an old existing wellbore, while the wellbore locations are selected in an effort to more efficiently drain each reservoir. The vast majority of the PUD targets are up-dip offsets to wells that produced from a sub-optimal position within a particular zone.

Facilities

We own and operate a production facility at WCBB that includes four production tank batteries, eight natural gas compressors, a storage barge facility, a dock, a dehydration unit and a salt water disposal system.

Recent and Future Activity

In 2013, we recompleted 87 gross and net wells and drilled 22 gross and net wells at WCBB. Of the 22 new wells drilled at WCBB in 2013, 21 were completed as producers and one was being drilled at year end. As of February 14, 2014, we had recompleted nine wells during 2014, drilled one well and were in the process of drilling one additional well in our WCBB field. Of the 22 wells drilled in 2013, 22 were considered deep wells. The 21 productive wells, with total depths ranging from 8,100 to 10,104 feet, have approximately 2,225 feet of aggregate apparent net pay. We currently anticipate drilling 22 to 24 gross and net wells at WCBB during 2014.

Production Status

In the fourth quarter of 2013, our production at WCBB was approximately 346,736 net BOE, or an average of 3,769 BOE per day, 97% of which was from oil and 3% of which was from natural gas. From January 1, 2014 through January 31, 2014, our average net daily production at WCBB was approximately 3,158 BOE, 100% of which was from oil. The decrease in average net daily production in January 2014 was due to normal production declines and the impact of extreme winter conditions.

East Hackberry Field

Location and Land

The East Hackberry field in Louisiana is located along the western shore and the land surrounding Lake Calcasieu, 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 80.309% average NRI) in certain producing oil and natural gas properties situated in the East Hackberry field. As of December 31, 2013, we held beneficial interests in approximately 4,512 acres, including the Erwin Heirs Block, which is located on land, and the adjacent State Lease 50 Block, which is located primarily in the shallow waters of Lake Calcasieu. We licensed approximately 54 square miles of 3-D seismic data covering a portion of the area and have received a processed version of the seismic data.

Area History and Production

The East Hackberry field was discovered in 1926 by Gulf Oil Company, now Chevron Corporation, by a gravitational anomaly survey. The massive shallow salt stock presented an easily recognizable gravity anomaly indicating a productive field. Initial production began in 1927 and has continued to the present. The estimated cumulative oil and condensate production through 2013 was over 3,426 MBOE and 330.4 Bcf of casinghead gas production. A total of 254 wells have been drilled on our portion of the field. As of December 31, 2013, 47 wells had daily production, 86 were shut-in and three had been converted to salt water disposal wells. The remaining 118 wells had been plugged and abandoned.

Geology

The Hackberry field is a major salt intrusive feature, elliptical in shape as opposed to a classic "dome," divided into east and west field entities by a saddle. Structurally, our East Hackberry acreage is located on the eastern end of the Hackberry salt ridge. There are over 30 pay zones at this field. The salt intrusion formed a series of structurally complex and steeply dipping fault blocks in the Lower Miocene and Oligocene age rocks. These fault blocks serve as traps for hydrocarbon accumulation. Our wells currently produce from perforations found between 5,100 and 12,200 feet.

Facilities

We have a field office that serves both the East and West Hackberry fields. In addition, we own and operate three production facilities at East Hackberry that include two land based tank batteries, a production barge, five natural gas compressors, dehydration units and salt water disposal systems.

Recent and Future Activity

During 2013 at East Hackberry, we recompleted 61 gross and net wells and drilled 14 gross and net land wells and two gross and net wells on water. Of the 16 wells drilled during 2013, 13 were completed as producing wells, one was non-productive, one was waiting on completion and one was being drilled at year end. As of February14, 2014, we had recompleted seven wells during 2014, drilled one well and were in the process of drilling one additional well in our East Hackberry field. We currently intend to drill ten to twelve gross and net wells in our East Hackberry field during 2014.

Production Status

In the fourth quarter of 2013, our net production at East Hackberry was approximately 188,536 BOE, or an average of 2,049 BOE per day, 90% of which was from oil and 10% of which was from natural gas. From January 1, 2014 through January 31, 2014, our average net daily production at East Hackberry was approximately 2,431 BOE, 93% of which was from oil and 7% of which was from natural gas. The increase in production in 2014 is a result of our 2013 drilling and recompletion activities.

West Hackberry Field

Location and Land

The West Hackberry field is located on land and is five miles west of Lake Calcasieu in Cameron Parish, Louisiana, approximately 85 miles west of Lafayette and 15 miles inland from the Gulf of Mexico. We own a 100% working interest (approximately 83.333% NRI) in 1,192 acres within the West Hackberry field. Our leases at West Hackberry are located within two miles of one of the United States Department of Energy's Strategic Petroleum Reserves.

Area History

The first discovery well at West Hackberry was drilled in 1938 and the field was developed by Superior Oil Company, now ExxonMobil Corporation, between 1938 and 1988. The estimated cumulative oil and condensate production through 2013 was 344 MBOE and 140 Bcf of natural gas. There have been 40 wells drilled to date on our portion of West Hackberry. Currently, four of such wells are producing, 19 are shut-in and one has been converted to a saltwater disposal well. The remaining 16 wells have been plugged and abandoned.

Geology

Structurally, our West Hackberry acreage is located on the western end of the Hackberry salt ridge. There are over 30 pay zones at this field. West Hackberry consists of a series of fault-bounded traps in the Oligocene-age Vincent and Keough sands associated with the Hackberry Salt Ridge. Recoveries from these thick, porous, water-drive reservoirs have resulted in per well cumulative production of almost 700 MBOE.

Recent and Future Activity

During 2013 at West Hackberry, we recompleted two gross and net wells and drilled two gross and net wells both of which were productive as of year end. As of February14, 2014, no new wells had been drilled in our West Hackberry field.

Production Status

In the fourth quarter of 2013, our net production at West Hackberry was approximately 6,466 BOE, or an average of 70 BOE per day, 100% of which was from oil. From January 1, 2014 through January 31, 2014, our average net daily production at West Hackberry was approximately 110 BOE and was 100% from oil.

Facilities

We own and operate a production facility at West Hackberry that includes a land based tank battery and salt water disposal system.

Niobrara Formation (Northwestern Colorado)

Location and Land

Effective as of April 1, 2010, we acquired leasehold interests in the Niobrara Formation in Northwestern Colorado and, as of December 31, 2013, we held leases for approximately 7,481 net acres. In 2013, no wells were spud on our Niobrara Formation acreage.

Area History

The Niobrara Formation is a shale oil rock formation located in Colorado, Northwest Kansas, Southwest Nebraska, and Southeast Wyoming. Oil and natural gas can be found at depths of 3,000 to 14,000 feet and is drilled both vertically and horizontally. The Upper Cretaceous Niobrara Formation has emerged as another potential crude oil resource play in various basins throughout the northern Rocky Mountain region. As with most resource plays, the Niobrara Formation has a history of producing through conventional technology with some of the earliest production dating back to the early 1900s. Natural fracturing has played a key role in producing the Niobrara Formation historically due to the low porosity and low permeability of the formation. Because of this, conventional production has been very localized and limited in area extent. We believe the Niobrara Formation can be produced on a more widespread basis using today's horizontal multi-stage fracture stimulation technology where the Niobrara Formation is thermally mature.

Geology

The Niobrara Formation oil play in Northwestern Colorado is located between the Piceance Basin to the south and the Sand Wash Basin to the north. Rocks mainly consist of interbedded organic-rich shales, calcareous shales and marlstones. It is the fractured marlstone intervals locally known as the Buck Peak, Tow Creek and Wolf Mountain benches that account for the majority of the areas production. These fractured carbonate reservoirs are associated with anticlinal, synclinal and monoclinal folds, and fault zones. This proven oil accumulation is considered to be continuous in nature and lightly explored. Source rocks are predominantly oil prone and thermally mature with respect to oil generation. The producing intervals are geologically equivalent to the Niobrara Formation reservoirs of the DJ and Powder River Basins, which are currently emerging as a major crude resource play.

Production Status

In the fourth quarter of 2013, our net production from our Niobrara Formation acreage was approximately 4,552 BOE, or an average of 49 BOE per day, 100% of which was from oil. From January 1, 2014 through January 31, 2014, our average daily net production from our Niobrara Formation acreage was approximately 55 BOE, 100% of which was from oil.

Facilities

There are typical land oil and gas processing facilities in the Niobrara Formation. Our facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activity

We have completed a 60 square mile 3-D seismic survey over our Craig Dome prospect and have received a processed version of the seismic. We do not anticipate drilling any wells in the Niobrara Formation during 2014.

Bakken Formation

Location and Land

The Bakken Formation is located in the Williston Basin areas of Western North Dakota and Eastern Montana. As of December 31, 2013, we held approximately 864 net acres, interests in 13 wells and an overriding royalty interests in certain existing and future wells.

Production Status

In the fourth quarter of 2013, our net production from our Bakken Formation acreage was approximately 2,412 BOE, or an average of 26 BOE per day, of which 90% was from oil and 10% was from NGLs. From January 1, 2014 through January 31, 2014, our average net daily production from this acreage was approximately 93 BOE, of which 88% was from oil and 12% was from natural gas.

Facilities

There are typical land oil and gas processing facilities in the Williston Basin. The facilities located at well locations include storage tank batteries, oil/gas/water separation equipment and pumping units.

Recent and Future Activities

Six gross (1.3 net) wells were drilled on our Bakken Formation acreage in 2013. As of February 14, 2014, no new wells had been drilled on our Bakken Formation acreage in 2014.

Additional Properties

Louisiana. In addition to our interests in the WCBB, East Hackberry and West Hackberry fields, we also own working interests and overriding royalty interest in various fields in Louisiana, Texas and Oklahoma as described in the following table as of December 31, 2013:

Field	State	Parish/ County	Acreage Working Interest	Overriding Royalty Interests	Producing Wells	Non-Producing Wells
Deer Island	Louisiana	Terrebonne	3.125%	—%	1	—
Napoleonville	Louisiana	Assumption	—%	2.5%	3	—
Crest	Texas	Ochiltree	2%	—%	1	—
Eagle City South	Oklahoma	Dewey	1.04%	—%	1	—
Fay South	Oklahoma	Blaine	0.301%	—%	1	—
Squaw Cheek	Oklahoma	Blaine	0.694%	—%	1	—

Our Equity Investments

Permian Basin. On October 11, 2012, we contributed to Diamondback, prior to the closing of the Diamondback IPO, all of our oil and natural gas interests in the Permian Basin. At the closing of this contribution, Diamondback issued to us (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to us at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of a Diamondback subsidiary as of the date of this contribution. In January 2013, we received an additional payment from Diamondback of $18.6 million as a result of this post-closing adjustment. As of December 31, 2013, we owned approximately 7.2% of Diamondback's outstanding common stock. Our investment in Diamondback is accounted for as an equity method investment.

Grizzly Oil Sands. We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc., an entity owned by certain investment funds managed by Wexford Capital LP, or Wexford. As of December 31, 2013, Grizzly had approximately 830,000 net acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada and had three oil sands projects in various stages of development and had drilled an aggregate of 255 core holes and six water supply test wells on ten separate lease blocks and conducted a number of seismic programs. Regulatory approval of Grizzly's 11,300 barrel per day steam-assisted gravity drainage, or SAGD, oil sand project at Algar Lake was received in the fourth quarter of 2011. During 2012, an 11 kilometer road was constructed to the project site, water and natural gas supply pipelines were installed, central plant modules were assembled, transported to the project site and lifted into place, ten production well pairs were drilled and completed and well pad modules and flow lines back to the central plant were installed. Steam generation commenced and was circulating through the plant and well pad facilities by year-end 2013. Reservoir steam injection commenced in January 2014 with first production expected by the end of the first quarter of 2014. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres. An initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. A 29 well delineation drilling program was completed in the first quarter of 2013 over the development application area and a 2D seismic program covering approximately 80 kilometers is currently underway to more fully define the development area. At the Thickwood thermal project, Grizzly's activities included the completion of a 22 well core hole drilling program and the acquisition of 31 kilometers of seismic data. A development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. Grizzly has also entered into a memorandum of understanding that outlines the rate structure for a ten year agreement with Canadian National Railway Company, or CN, to transport its bitumen to the U.S. Gulf Coast via CN's rail network. Grizzly expects that this arrangement will provide consistent access to Brent-based pricing from Grizzly's Algar Lake project. Grizzly is developing the Windell Terminal, a rail loadout facility in Conklin, Alberta, and the Paulina Terminal, a rail to barge off-load facility on the lower Mississippi River. Construction of the 15,000 barrel per day Windell Terminal, proximate to its May River lease, is expected to be completed and ready for operation by the end of the first quarter of 2014. In the U.S. Gulf Coast, Grizzly has begun engineering design work of the 40,000 barrel per day Paulina Terminal project located on the lower Mississippi River and has filed development permits.

Thailand. We own a 23.5% ownership interest in Tatex Thailand II, LLC, or Tatex II. Tatex II, a privately held entity, holds 85,122 of the 1,000,000 outstanding shares of APICO, an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field. Our investment is accounted for on the equity method. Tatex II accounts for its investment in APICO using the cost method. In December 2006, first gas sales were achieved at the Phu Horm field located in northeast Thailand. Phu Horm's initial gross production was approximately 60 million cubic feet per day. For 2013, net gas production was approximately 88 MMcf per day and condensate production was 382 barrels per day. Hess Corporation, or Hess, operates the field with a 35% interest. Other interest owners include APICO (35% interest), PTT Exploration and Production Public Company Limited (20% interest) and ExxonMobil (10% interest). Our gross working interest (through Tatex II as a member of APICO) in the Phu Horm field is 0.7%. Since our ownership in the Phu Horm field is indirect and Tatex II's investment in APICO is accounted for by the cost method, these reserves are not included in our year-end reserve information.

We own a 17.9% ownership interest in Tatex Thailand III, LLC, or Tatex III. Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. In 2009, Tatex III completed a 3-D seismic survey on this concession. The first well was drilled on our concession in 2010 and was temporarily abandoned pending further scientific evaluation. In March 2011, the second well was drilled to a depth of 15,026 feet and logged approximately 5,000 feet of apparent possible gas saturated column. Pressure buildup information confirmed that this wellbore lacked the permeability to deliver commercial quantities of gas. However, despite an apparently well-developed porosity system suggesting potential for a large amount of gas in place, testing of the well did not exhibit that there was sufficient permeability to produce in commercial quantities. In October 2013, Tatex III spud the TEW-K well, located to the south of the TEW-E well. The well tested gas at non-commercial rates. During drilling, the well flowed gas with rates as high as 20 MMcf per day of gas; however, no acceptable sustainable rate was established.

Other Investments. In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the first quarter of 2013, we participated in the formation of Stingray Energy with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure, Stingray Cementing and Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk and Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our

Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Midstream which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. See Note 5 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation. In addition, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Marketing and Customers

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the demand for oil and natural gas and the level of domestic production and imports of oil, the proximity and capacity of gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of gas sold in interstate commerce. The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our Southern Louisiana oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt's trade month average P+ value, plus or minus the Platt's HLS/WTI trade month average differential less $2.00 per barrel for transportation. Shell is the purchaser of our Utica Shale oil and pays us NYMEX less $10.00 per barrel. Markwest Utica purchases our Utica Shale NGLs. We have agreements in place with various purchasers for our Utica Shale natural gas production. In 2013, our Utica Shale natural gas was sold under monthly, seasonal and long term contracts and, as needed, through trades. Pricing was based on Dominion South Point (Dominion Eastern and Dominion Transmission) or Texas Eastern M2 Zone, plus or minus the market differential. As discussed below under "- Transportation and Takeaway Capacity," we have entered into agreements to transport our natural gas production out of the Utica Basin in 2014 and beyond.

During the year ended December 31, 2013, we sold approximately 99% of our oil production to Shell Trading Company, or Shell, 100% of our natural gas liquids production to Markwest Utica and 32%, 31% and 17% of our natural gas production to Sequent Energy Management, L.P., or Sequent, Hess and Interstate Gas Supply, Inc., or Interstate Gas, respectively. During the year ended December 31, 2012, we sold approximately 92% and 8% of our oil production to Shell and Diamondback O&G LLC (a wholly-owned subsidiary of Diamondback formerly known as Windsor Permian LLC), or Diamondback O&G, respectively, 91% of our natural gas liquids production to Diamondback O&G and 41%, 18% and 16% of our natural gas production to Noble Americas Gas, Hess and Chevron, respectively. During 2011, we sold 93% and 7% of our oil production to Shell and Diamondback O&G, respectively, 100% of our natural gas liquids production to Diamondback O&G, and 50%, 27% and 22% of our natural gas production to Hilcorp Energy Company, Chevron and Diamondback O&G, respectively.

As of December 31, 2013, we had approximately 183,00 MMBtu per day of firm sales contracted with third parties. Of these sales, 33,000 MMBtu per day, 100,000 MMBtu per day and 50,000 MMBtu per day expire in 2015, 2016 and 2017, respectively.

Transportation and Takeaway Capacity

In Ohio, as of December 31, 2013, we had entered into firm transportation contracts for 2014, 2015 and 2016 for an aggregate of approximately 427,000 MMBtu per day, 677,000 MMBtu per day and 650,000 MMBtu per day, respectively. We are actively seeking to secure additional firm transportation contracts for incremental volumes from our Utica Shale acreage and expect to finalize additional contracts in the first half of 2014. Our primary long-haul firm transportation commitments include the following:

- 194,000 MMBtu per day of firm capacity on ANR Pipeline Company facilities that will allow us to reach the Michigan, Chicago and Wisconsin natural gas markets in 2014.
- 200,000 MMBtu per day of firm capacity on Tennessee Gas Pipeline facilities beginning in mid-2014 and, by the end of 2014, we expect to be able to reach Gulf Coast delivery points with the full contracted volumes; and
- 50,000 MMBtu per day of firm capacity to the Gulf Coast through Texas Gas Transmission facilities beginning in 2016.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. We continue to actively identify and evaluate additional takeaway capacity to facilitate production growth in our Utica Basin position.

Regulation

Regulation of Gas and Oil Production

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

We own interests in a number of producing oil and natural gas properties located along the Louisiana Gulf Coast, and in the Utica Shale in Eastern Ohio, the Niobrara Formation in Northwestern Colorado and the Bakken Formation in Western North Dakota and Eastern Montana. The states in which our fields are located in regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields and the spacing and operation of wells. In addition, regulations governing conservation matters aimed at preventing the waste of oil and natural gas resources could affect the rate of production and may include maximum daily production allowables for wells on a market demand or conservation basis.

Environmental Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental agencies, such as the U.S. Environmental Protection Agency, or the EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, as amended, or RCRA, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute “solid wastes” that are subject to the less stringent requirements of non-hazardous waste provisions. However, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as CERCLA or the “Superfund” law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original 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 current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), 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. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” the Safe Drinking Water Act, the Oil Pollution Act, or OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. In November 2012, we and other entities involved in our WCBB field operations received a government subpoena, to which we have responded, for the production of documents and other information related primarily to a discharge of produced water that was allegedly identified by the U.S. Coast Guard in March 2012. We have had continuing communications with the government concerning these events and have been informed that the government may pursue claims against us and certain of our field personnel. We are continuing to cooperate with the investigation. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in April 2014. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act, or OPA, is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, in August 2012, the EPA approved final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail under the caption "-*Regulation of Hydraulic Fracturing*." These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change. Many nations have agreed to limit emissions of "greenhouse gases" pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are "greenhouse gases," or GHGs, regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol at this time, several states or geographic regions have adopted legislation and regulations to reduce emissions of greenhouse gases. Additionally, on April 2, 2007, the U.S. Supreme Court ruled, in *Massachusetts, et al. v. EPA*, that the EPA has the authority to regulate carbon dioxide emissions from automobiles as "air pollutants" under the federal Clean Air Act. Thereafter, in December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the "tailoring rule") in May 2010, and it also became effective January 2011, although on October 15, 2013, the U.S. Supreme Court granted review of certain issues related to EPA's authority to regulate such emissions from stationary sources. Oral argument on the issues before the Supreme Court was heard on February 24, 2014, and a decision is expected by July 2014.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In addition, the EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards for new coal-fired and natural-gas fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In addition, the U.S. 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. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. 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 corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Currently, while we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Endangered Species Act

Environmental laws such as the Endangered Species Act, as amended, or the ESA, may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the U.S., and prohibits taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to insure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities on federal lands may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. The U.S. Fish and Wildlife Service may identify, however, previously unidentified endangered or threatened species or may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species, which could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Occupational Safety and Health Act

We are also subject to the requirements of OSHA and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as “Class II” UIC wells. On February 12, 2014, the EPA published revised UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities, may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. The EPA is encouraging state programs to review and consider use of the draft guidance. At the same time, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress continues to consider legislation to amend the SDWA.

In August 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule includes a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that may be responsive to some of these requests.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts, the results of which are expected in 2014. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The U.S. 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. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC 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 shale formations by means of hydraulic fracturing, and the U.S. 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.

Some states in which we operate or hold oil and natural gas interests have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, in January 2012, the Ohio Department of Natural Resources issued a temporary moratorium on the development of hydraulic fracturing disposal wells in northeast Ohio, to study the relationship between these wells and minor earthquakes reported in the area. The Texas Railroad Commission and Louisiana Department of Natural Resources recently adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act (OSHA) to state regulators and on a public internet website. Effective August 26, 2011, Montana adopted hydraulic fracturing disclosure regulations under which well operators must provide information in drilling permit applications on the estimated volume and types of materials to be used in the proposed hydraulic fracturing activities. Upon completion of the well, well operators must provide the Montana Board of Oil and Gas Conservation with the volume and type of chemicals used, including the additive type, chemical ingredient names, and Chemical Abstracts Service, or CAS, number, subject to certain trade secret protections. On April 1, 2012, the North Dakota Industrial Commission enacted regulations requiring hydraulic fracturing well operators to disclose the hydraulic fluid composition, including the trade name, supplier, ingredients, CAS Number, and the maximum ingredient concentrations of all additives in the hydraulic fracturing fluid. Colorado enacted rules requiring similar disclosures on January 30, 2012. Also, on May 16, 2013, the U.S. Department of Interior, or DOI, issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm its wells meet certain construction standards and (iii) establish site plans to manage flowback water. DOI is expected to issue a final rule in 2014. We plan to use hydraulic fracturing in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the states in which we operate, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. 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 as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Other Regulation of the Oil and Natural Gas Industry

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

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

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

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

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

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

State Regulation. The states in which we operate regulate the drilling for, and the production and gathering of, oil and natural gas, including through requirements relating to the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may also regulate rates of production and may establish maximum daily production allowables from wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Operational Hazards and Insurance

The oil business involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties for operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of certain wells, oil pollution, third party liability, workers compensation and employers' liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery. Additionally, our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these events could cause a significant disruption to our business. For example, we experienced production interruptions in 2005 and 2006 from Hurricanes Katrina and Rita and, in 2008, from Hurricanes Gustav and Ike. A loss not fully covered by insurance could have a material adverse affect on our financial position, results of operations and cash flows.

Currently, we have general liability insurance coverage with an annual aggregate limit of up to $21.0 million which includes sudden and accidental pollution for the effects of onshore and offshore pollution on third parties arising from our operations. For our offshore WCBB properties, we also have a $38.0 million property physical damage policy which insures against most operational perils, such as explosions, fire, vandalism, theft, hail and windstorms, provided, however, that this policy is limited to $12.5 million for damages arising as a result of a named windstorm. In the event of a loss under this policy, we have up to $12.6 million of business interruption coverage available after a 90 day waiting period. All of our insurance coverage includes deductibles of up to $250,000 per occurrence ($1.25 million in the case of a named windstorm) that must be met prior to recovery. Additionally, our insurance is subject to customary exclusions and limitations. We reevaluate the purchase of insurance, policy terms and limits annually each May. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

We carry control of well insurance for all of our Utica Shale wells and several Southern Louisiana wells. We also require all of our third party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider.

We have prepared and have in place spill prevention control and countermeasure plans for each of our principal facilities in response to federal and state requirements. The plans are reviewed annually and updated as necessary. As required by applicable regulations, our facilities are built with oil containment features and we own certain oil containment equipment, such as oil boom to surround drill sites and production facilities if needed. In addition, we have emergency response companies on retainer. These companies specialize in the clean up of hydrocarbons as a result of spills, blow-outs and natural disasters, and are on call to us 24 hours a day, seven days a week when their services are needed. We pay these companies a retainer plus additional amounts when they provide us with clean up services. Our aggregate payments for the retainer and clean up services during 2013 and 2012 were approximately $0.7 million and $0.1 million, respectively. While these companies have been able to meet our service needs when required from time to time in the past, it is possible that the ability of one or more of them to provide services to us in the future, if and when needed, could be hindered or delayed in the event of a widespread disaster. However, in light of the areas in which we operate and the nature of our production, we believe other companies would be available to us in the event our primary remediation companies are unable to perform. To supplement our planning and operation activities in Ohio, we also actively manage an incident response planning program and coordinate with applicable state agency personnel on spills and releases. We also participate in Ohio's Emergency Planning and Community Right to Know Act (EPCRA) program, which includes reporting of various materials used or stored on-site as well as notification to state and local emergency response centers, such as local fire departments, for emergency planning purposes.

Headquarters and Other Facilities

We own an approximately 28,500 square foot office building in Oklahoma City, Oklahoma that serves as our corporate headquarters. Additionally, we lease approximately 20,800 square feet of office space in other buildings in Oklahoma City. We also own an approximately 12,500 square foot building in Lafayette, Louisiana. This building contains approximately 6,200 square feet of finished office area and 6,300 square feet of clear span warehouse area. We also lease approximately 3,700 square feet in a building in Lafayette that we use as our Louisiana headquarters. We recently completed construction of an approximately 5,700 square foot office building in St. Clairsville, Ohio that will serve as our Ohio headquarters. In addition, we lease 1,400 square feet of office space in St. Clairsville, Ohio. Each of these properties is suitable and adequate for its use.

Employees

At December 31, 2013, we had 118 employees. An unrelated Louisiana well servicing company provides all necessary field personnel needed to operate the WCBB and the Hackberry fields. During 2013, certain of our employees performed management and administrative services for affiliated companies for which we were reimbursed approximately $1.4 million.

Our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on the Investor Relations page of our website at www.gulfportenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on our website, or on other websites that may be linked to our website, is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

Risks Related to our Business and Industry

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our profitability.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including:

- worldwide and domestic supplies of oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas;
- the expected rates of declining current production;
- weather conditions, including hurricanes, and other natural disasters that can affect oil and natural gas operations over a wide area;
- the level of consumer demand;
- the price and availability of alternative fuels;
- technical advances affecting energy consumption;
- risks associated with operating drilling rigs;
- the availability of pipeline capacity and other transportation facilities;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- political or economic instability or armed conflict in oil and natural gas producing regions, including the Middle East, Africa, South America and Russia; and
- the overall domestic and global economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past six years, the posted price for West Texas intermediate light sweet crude oil, which we refer to herein as West Texas Intermediate or WTI, has ranged from a low of $30.28 per barrel, or Bbl, in December 2008 to a high of $145.31 per Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per MMBtu in September 2009 to a high of $13.31 per MMBtu in July 2008. During 2012, West Texas Intermediate prices ranged from $80.48 to $108.99 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.80 to $3.80 per MMBtu. On December 31, 2013, the West Texas Intermediate posted price for crude oil was $98.55 per barrel and the Henry Hub spot market price of natural gas was $4.19 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves. In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development results deteriorate, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the United States mortgage market and a weak real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our oil, natural gas and natural gas liquids, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made and expect to make in the future substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. For example, we currently estimate our exploration and production capital expenditures for 2014 to be in the range of $675.0 million to $725.0 million and an additional $225.0 million to $275.0 million for acreage acquisitions in the Utica Shale.

Historically, we have financed capital expenditures primarily with cash flow from operations, the issuance of equity and debt securities and borrowings under our bank and other credit facilities. Our cash flow from operations and access to capital are subject to a number of variables, including:

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

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2014 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies.

Our success depends on finding, developing or acquiring additional reserves, which requires significant capital expenditures.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made, and expect to make in the future, substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. We may not have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. If we are unable to replace our current production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently operate, which could result in unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

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

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

If we are unable to complete capital projects in a timely manner, our business, financial condition, results of operations and cash flows could be materially and adversely affected.

Delays related to capital spending programs involving engineering, procurement and construction of facilities (including improvements and repairs to our existing facilities) could adversely affect our ability to achieve forecasted internal rates of return and operating results. Delays in making required changes or upgrades to our facilities could subject us to fines or penalties as well as affect our ability to supply certain products we produce. Such delays may arise as a result of unpredictable factors, many of which are beyond our control, including:

- denial of or delay in receiving requisite regulatory approvals and/or permits;
- unplanned increases in the cost of construction materials or labor;
- disruptions in transportation of components or construction materials;
- adverse weather conditions, natural disasters or other events (such as equipment malfunctions, explosions, fires or spills) affecting our facilities, or those of vendors or suppliers;
- shortages of sufficiently skilled labor, or labor disagreements resulting in unplanned work stoppages;
- market-related increases in a project's debt or equity financing costs; and
- nonperformance by, or disputes with, vendors, suppliers, contractors or subcontractors.

Any one or more of these factors could have a significant impact on our ongoing capital projects.

Our Canadian oil sands projects are complex undertakings and may not be completed at our estimated cost or at all.

We, through our wholly-owned subsidiary Grizzly Holdings Inc., own a 24.9% interest in Grizzly. The remaining interest in Grizzly is owned by Grizzly Oil Sands Inc., an entity owned by certain investment funds managed by Wexford. As of December 31, 2013 Grizzly had approximately 830,000 net acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. Our total net investment in Grizzly was approximately $191.5 million as of December 31, 2013. Grizzly has three oil sands projects in various states of development. At Grizzly's 11,300 barrel per day SAGD oil sand project at Algar Lake, reservoir steam injection commenced in January 2014 with first production expected by the end of the first quarter of 2014. In the first quarter of 2012, Grizzly acquired the May River property comprising approximately 47,000 acres and an initial 12,000 barrel per day development application was filed with the regulatory authorities in the fourth quarter of 2013, covering the eastern portion of the May River lease. At Grizzly's Thickwood thermal project, a development application for a 12,000 barrel per day oil sands project at Thickwood was filed in the fourth quarter of 2012. In addition, Grizzly is developing a rail loadout facility in Conklin, Alberta and a rail to barge off-load facility on the lower Mississippi River. These are complex projects and additional financing may be required. There can be no assurance that such financing, if required, could be obtained on commercially reasonable terms or at all, or that if one or more of these projects are completed that they will be successful or that we realize a return on our investment.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for and wage rates of qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

We rely on a few key employees whose absence or loss could disrupt our operations resulting in a loss of revenues.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services, particularly the loss of Michael G. Moore, our Interim Chief Executive Officer, President and Chief Financial Officer, our geophysicists or our lead operations personnel, could disrupt our operations resulting in a loss of revenues. Our executives are not restricted from competing with us if they cease to be employed by us, except under certain limited circumstances prohibiting competition while making use of our trade secrets. We are party to an employment agreement with each of these executive officers. As a practical matter, however, employment agreements may not assure the retention of our employees. Further, we do not maintain “key person” life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Estimates of oil and natural gas reserves are uncertain and may vary substantially from actual production.

There are numerous uncertainties associated with estimating quantities of proved reserves and in projecting future rates of production and timing of expenditures. The reserve information herein represents estimates prepared by (i) Netherland, Sewell & Associates, Inc., or NSAI, with respect to our WCBB, Hackberry and Niobrara fields at each of December 31, 2013, 2012 and 2011, (ii) Ryder Scott with respect to our Utica Shale acreage at December 31, 2013 and 2012 and our Permian Basin acreage at December 31, 2011 (which acreage has been contributed to Diamondback as described in Item 1. “Our Equity Investments”) and (iii) our personnel with respect to our overriding royalty and non-operated interests at December 31, 2013, 2012 and 2011. Petroleum engineering is not an exact science. Information relating to our proved oil and natural gas reserves is based upon engineering estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil and natural gas prices, future operating costs, severance and excise taxes, capital expenditures and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Estimates of reserves as of year-end 2013, 2012 and 2011 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2013, 2012 and 2011, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The present value of future net revenues from our proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net revenue from our proved reserves for 2013, 2012 and 2011 on an average price equal to the unweighted arithmetic average of prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2013, 2012 and 2011, respectively, in accordance with the revised guidelines of the SEC applicable to reserves estimates for such years. However, actual future net revenues from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

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

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 35.2% of our total estimated proved reserves at December 31, 2013, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources in connection with our equity investment in Grizzly and the indicated level of reserves or recovery of bitumen may not be realized.

There are numerous uncertainties in estimating quantities of bitumen reserves and resources, and the indicated level of reserves or recovery of bitumen may not be realized. In general, estimates of economically recoverable bitumen reserves and the future net cash flow from such reserves are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves. Reserve and resource estimates may require revision based on actual production experience. Reserve and resources estimates are determined with reference to assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. The actual gravity or quality of bitumen to be produced from Grizzly's lands cannot be determined at this time.

The marketability of our production is dependent upon compressors, gathering lines, transportation barges and other facilities, certain of which we do not control. When these facilities are unavailable, our operations can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of natural gas lines and transportation barges owned by third parties. In general, we do not control these transportation facilities and our access to them may be limited or denied. A significant disruption in the availability of these transportation facilities or our compression and other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. We are at particular risk with respect to oil and natural gas produced at our WCBB field and from our Utica Shale acreage. In October 2006, for example, a natural gas line in our WCBB field operated by our natural gas purchaser was ruptured by a third party contractor, requiring the field to be shut in for approximately seven weeks until the line could be repaired. Further, we are dependent on our oil purchaser to provide the barges necessary to transport our oil production from the WCBB field. With respect to our Utica Shale acreage where we are focusing a significant portion of our exploration and development activity, historically there has been no or only limited infrastructure in this area and the commencement of production from our initial and subsequent wells on our Utica Shale acreage has been delayed due to challenges in obtaining rights-of-way and acquiring necessary state and federal permitting and the completion of facilities by our midstream service provider. If we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter compression or other production related difficulties, we will be required to shut in or curtail production from the impacted field(s). Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Substantially all of our producing properties are located in Eastern Ohio and Louisiana, making us vulnerable to risks associated with operating in these regions.

Our largest fields by production are located in Eastern Ohio and approximately five miles off the coast of Louisiana in a shallow bay with water depths averaging eight to ten feet. As a result, we may be disproportionately exposed to the impact of delays or interruptions of production in these geographic regions caused by weather conditions such as snow, ice, fog, rain, hurricanes or other natural disasters or lack of field infrastructure. Losses could occur for uninsured risks or in amounts in excess of any existing insurance coverage. We may not be able to obtain and maintain adequate insurance at rates we consider reasonable and it is possible that certain types of coverage may not be available.

Our identified drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified over 800 drilling locations on our Louisiana, Ohio and Western Colorado properties. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, oil and natural gas prices, inclement weather, costs, drilling results and regulatory changes. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;

- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

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

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, gas leaks, ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. We may face liability for environmental damage caused by previous owners of properties purchased by us, which liabilities may or may not be covered by insurance. For example, we are a defendant in a private civil lawsuit in Cameron Parish, Louisiana brought against over 20 oil and natural gas companies for alleged surface contamination as distributed elsewhere in this report. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. In November 2012, we and other entities involved in our WCBB field operations received a government subpoena, to which we have responded, for the production of documents and other information related primarily to an alleged discharge of produced water in March 2012. We have had continuing communications with the government concerning these events and have been informed that the government may pursue claims against us and certain of our field personnel. We are continuing to cooperate with the investigation. Additionally, in September 2013, we entered a compliance agreement with the Ohio Division of Oil and Gas Resources Management concerning aspects of our operations at seven drilling sites in Ohio. See "-We have entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management and, if we fail to comply with the conditions of the compliance agreement, all or part of our drilling and producing operations in the State of Ohio may be suspended."

Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

We have entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management and, if we fail to comply with the conditions of the compliance agreement, all or part of our drilling and producing operations in the State of Ohio may be suspended.

In September 2013, we entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management, or the Division, concerning aspects of our operations at seven drilling sites in Ohio. We had previously notified the Division of brine contamination at these drilling sites. After receipt of this notification, the Division conducted an investigation and determined that certain contaminants were escaping from underneath the containment liners at these locations. In the compliance agreement, we agreed, among other things, to conduct our production operations in compliance with all requirements of applicable regulations, implement a remediation plan and make a payment of $250,000. We are continuing to work with the Division to fulfill our obligations under the compliance agreement and to enhance our materials handling protocols. If the Chief of the Division determines that we have failed to comply with the conditions set forth in the compliance agreement, the Chief may suspend all or part of our drilling and production operations in the State of Ohio for a period determined by the Chief, and we could incur additional penalties and costs.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We acquire significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient commercial quantities to cover the drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and many factors can adversely affect the economics of a well or property. Drilling operations may be curtailed, delayed or canceled as a result of unexpected drilling conditions, equipment failures or accidents, shortages of equipment or personnel, environmental issues and for other reasons. In addition, wells that are profitable may not meet our internal return targets, which are dependent upon the current and expected future market prices for oil and natural gas, expected costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. Drilling results in our newer oil and liquids-rich shale plays may be more uncertain than in shale plays that are more developed and have longer established production histories, and we can provide no assurance that drilling and completion techniques that have proven to be successful in other shale formations to maximize recoveries will be ultimately successful when used in newly developed shale formations.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. 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 other 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 the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the new techniques we are adopting, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

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, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

We have been an early entrant into the Utica Shale in Eastern Ohio. As a result, our drilling results in this area may vary, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We spud our first well, the Wagner 1-28H, on our Utica Shale acreage in February 2012 and, as of December 31, 2013, had spud 66 wells, 38 of which had been completed and were producing. In 2013, we spud 52 gross (39 net) wells, of which 24 were completed and are productive, one was non-productive, nine were waiting on a horizontal rig, 11 were waiting on completion and seven were still being drilled as of December 31, 2013. As of February 14, 2014, we had spud six gross (five net) wells during 2014 all of which were still drilling. In addition, 49 gross (2.6 net) wells were drilled by other operators on our Utica Shale acreage during 2013. We have seven rigs under contract on our Utica Shale acreage. We currently intend to drill 85 to 95 gross (64 to 71 net) wells on our Utica Shale acreage in 2014. While our costs to acquire undeveloped acreage in this emerging play have generally been less than those of later entrants into a developing play, our drilling results in this area are more uncertain than drilling results in areas that are developed and producing. Since the Utica Shale has limited production history and since we have limited experience drilling in this play, it is difficult to predict our future drilling results. Our cost of drilling, completing and operating wells in this area may be higher than initially expected, and the value of our undeveloped acreage in the Utica Shale may decline if drilling results are unsuccessful. We cannot assure you that unproved property acquired, or undeveloped acreage leased, by us in the Utica Shale or other emerging plays will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, the following:

- effectively controlling the level of pressure flowing from particular wells;
- landing our wellbore 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 wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, 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 unevaluated properties and the value of our undeveloped acreage could decline in the future.

We are not the operator of all of our oil and natural gas properties and therefore are not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

We are not the operator of all of the properties in which we have an interest, and have limited ability to exercise influence over the operations of such non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs, could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others will depend upon a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of the reserves.

In addition, when we are not the majority owner or operator of a particular oil or natural gas project, if we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

A significant portion of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

A significant portion of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. While none of our Utica Shale acreage leases are scheduled to expire until 2015, at that time 32% of our total Utica Shale undeveloped acreage as of December 31, 2013 will be subject to expiration, with 68% of such acreage expiring thereafter, although our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. As of December 31, 2013, leases representing 33%, 4%, 22%, 4% and 37%, respectively, of our total Niobrara Formation undeveloped acreage are scheduled to expire in 2014, 2015, 2016, 2017 and thereafter. The cost to renew expiring leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

Acquiring oil and gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. See Item 1. *"Business-Regulations-Environmental Matters and Regulation"* and Item 1. *"Business-Regulation-Other Regulation of The Oil and Natural Gas Industry"* for a description of the laws and regulations that affect us. See also "-Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities" above regarding a pending U.S. Environmental Protection Agency investigation regarding an alleged discharge of produced water in our WCBB field and a consent order we entered into with the Ohio Department of Natural Resources regarding our operations in the Utica Shale.

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 important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act, or SDWA, regulates the underground injection of substances through the Underground Injection Control, or UIC, program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and natural gas commissions. The Environmental Protection Agency, or EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, specifically as "Class II" UIC wells. On February 12, 2014, the EPA published revised UIC Program guidance for oil and natural gas hydraulic fracturing activities using diesel fuel. The guidance document describes how regulations of Class II wells, which are those wells injecting fluids associated with oil and natural gas production activities, may be tailored to address the purported unique risks of diesel fuel injection during the hydraulic fracturing process. The EPA is encouraging state programs to review and consider use of the draft guidance. At the same time, the White House Council on Environmental Quality is conducting an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

In August 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts, the results of which are expected in 2014. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory authorities. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC 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 shale formations by means of hydraulic fracturing, and the U.S. 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.

Several states in which we operate or hold oil and natural gas interests have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, in January 2012, the Ohio Department of Natural Resources, or ODNR, issued a temporary moratorium on the development of hydraulic fracturing disposal wells in northeast Ohio, to study the relationship between these wells and minor earthquakes reported in the area and the ODNR continues to monitor earthquake activity in proximity to wells undergoing hydraulic fracturing. The Texas Railroad Commission and Louisiana Department of Natural Resources recently adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of federal Occupational Safety and Health Act to state regulators and on a public internet website. Effective August 26, 2011, Montana adopted hydraulic fracturing disclosure regulations under which well operators must provide information in drilling permit applications on the estimated volume and types of materials to be used in the proposed hydraulic fracturing activities. Upon completion of the well, well operators must provide the Montana Board of Oil and Gas Conservation with the volume and type of chemicals used, including the additive type, chemical ingredient names, and Chemical Abstracts Service, or CAS, number, subject to certain trade secret protections. On April 1, 2012, the North Dakota Industrial Commission enacted regulations requiring hydraulic fracturing well operators to disclose the hydraulic fluid composition, including the trade name, supplier, ingredients, CAS Number, and the maximum ingredient concentrations of all additives in the hydraulic fracturing fluid. Colorado enacted rules requiring similar disclosures on January 30, 2012. Also, on May 6, 2013, the U.S. Department of Interior, or DOI, issued a revised proposed rule that seeks to require companies operating on federal and Indian lands to (i) publicly disclose the chemicals used in the hydraulic fracturing process; (ii) confirm its wells meet certain construction standards and (iii) establish site plans to manage flowback water. DOI is expected to issue a final rule in 2014. We plan to use hydraulic fracturing extensively in connection with the development and production of certain of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the states in which we operate, could reduce the volumes of oil and natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves

The adoption of derivatives legislation by the U.S. Congress 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 adoption of derivatives legislation by the U.S. Congress 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 U.S. Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The legislation was signed into law by the President on July 21, 2010. In its rulemaking under the legislation, the Commodities Futures Trading Commission, or CFTC, has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). The CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future 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 new legislation 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 derivative contracts in existence at that time, and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation 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 legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

The fiscal year 2014 budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In February 2013, the Governor of the State of Ohio proposed a plan to enact new severance taxes in fiscal 2014 and 2015. However, the Ohio State Senate did not include a severance tax increase in the version of the budget bill that it passed on June 7, 2013. The possibility remains that the severance tax increase on horizontal wells will resurface during compromise talks on the budget.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Continuing political and social attention to the issue of climate change has resulted in existing and pending international agreements and national, regional, state and local regulation associated with greenhouse gas emissions. While we are subject to certain federal GHG monitoring and reporting requirements, we do not believe that our operations are adversely impacted by existing climate change requirements and initiatives and, at this time, it is not possible to predict with certainty how potential future laws or regulations addressing GHG emissions would impact our businesses or demand for the oil and natural gas we produce. In particular, for example, in December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of such gases contribute to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA recently adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act. The motor vehicle rule, which became effective in January 2011, purports to limit emissions of GHGs from motor vehicles. The EPA adopted the stationary source rule (or the “tailoring rule”) in May 2010, and it also became effective January 2011, although on October 15, 2013, the U.S. Supreme Court granted review of certain issues related to EPA’s authority to regulate such emissions from stationary sources. Oral argument on the issues before the Supreme Court was heard on February 24, 2014, and a decision is expected by July 2014.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. The EPA has continued to adopt GHG regulations of other industries, such as a September 2013 proposed GHG rule that, if finalized, would set New Source Performance Standards for new coal-fired and natural-gas fired power plants, which could have an adverse effect on our financial condition and results of operations. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

In addition, the U.S. 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. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. 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 corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry, and state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the Natural Gas Act of 1938, or the NGA, exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission, or FERC. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish whether a pipeline performs a gathering function and therefore is exempt from FERC's jurisdiction under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is a fact-based determination. The classification of facilities as unregulated gathering is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress, which could cause our revenues to decline and operating expenses to increase and may materially adversely affect our business, financial condition or results of operations. In addition, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, which could have a material adverse effect on our business, financial condition or results of operations.

We face extensive competition in our industry.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

We depend upon a limited number of customers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The oil and natural gas we produce in Louisiana is sold to purchasers who service the areas where our wells are located. We sell the majority of our oil to Shell Trading Company, or Shell. Shell takes custody of the oil at the outlet from our oil storage barge. Our production from WCBB is being sold in accordance with the Shell posted price for West Texas/New Mexico Intermediate crude plus or minus Platt's trade month average P+ value, plus or minus the Platt's HLS/WTI differential less $2.00 per barrel for transportation. Shell is the purchaser of our Utica Shale oil and pays us NYMEX less $10.00 per barrel. Markwest Utica purchases our Utica Shale NGLs. We have agreements in place with various purchasers for our Utica Shale natural gas production. In 2013, our Utica Shale natural gas was sold under monthly, seasonal and long term contracts and, as needed, through trades. Pricing is based on Dominion South Point (Dominion Eastern and Dominion Transmission) or Texas Eastern M2 Zone, plus or minus the market differential. As discussed above under "- Transportation and Takeaway Capacity," we have entered into agreements to transport our natural gas production out of the Utica Basin in 2014 and beyond. During the year ended December 31, 2013, we sold approximately 99% of our oil production to Shell, 100% of our natural gas liquids production to Markwest Utica, and 32%, 31% and 17% of our natural gas production to Sequent, Hess and Interstate Gas, respectively. During 2012, we sold approximately 92% and 8% of our oil production to Shell and Diamondback O&G, respectively, 91% of our natural gas liquids production to Diamondback O&G, and 41%, 18% and 16% of our natural gas production to Noble Americas Gas, Hess and Chevron, respectively. During 2011, we sold 93% and 7% of our oil production to Shell and Diamondback O&G, respectively, 100% of our natural gas liquids production to Diamondback O&G and 22%, 27% and 50% of our natural gas production to Diamondback O&G, Chevron and Hilcorp Energy Company, respectively.

Our method of accounting for oil and natural gas properties may result in impairment of asset value.

We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Net capitalized costs are limited to the estimated future net revenues, after income taxes, discounted at 10% per year, from proven oil and natural gas reserves and the cost of the properties not subject to amortization. Such capitalized costs, including the estimated future development costs and site remediation costs, if any, are depleted by an equivalent units-of-production method, converting natural gas to barrels at the ratio of six Mcf of natural gas to one barrel of oil.

Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices for 2013, 2012 and 2011 adjusted for any contract provisions or financial derivatives, if any, that hedge oil and natural gas revenue, excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, less income tax effects related to differences between the book and tax basis of the oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability exceeds the ceiling, an impairment or noncash writedown is required. A ceiling test impairment can give us a significant loss for a particular period. Once incurred, a write down of oil and natural gas properties is not reversible at a later date, even if oil or gas prices increase. If prices of oil, natural gas and natural gas liquids decrease, we may be required to further write down the value of our oil and gas properties. Future non-cash asset impairments could negatively affect our results of operations.

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

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We have entered into forward sales contracts and fixed price swaps and may in the future enter into additional contracts for a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

We use fixed price derivative contracts to reduce price volatility associated with certain of our oil and natural gas sales. For the period from January 2014 through March 2014, we entered into fixed price swaps for 4,000 barrels of oil per day at a weighted average price of $104.75. For the period from April 2014 through December 2014 we entered into fixed price contracts for 2,000 barrels of oil per day at a weighted average price of $101.50. For January of 2014, we entered into fixed price swaps for 65,000 MMBtu per day at a weighted average price of $4.04. For the period from February 2014 through December 2014, we entered into fixed price swaps for 105,000 MMBtu per day at a weighted average price of $4.01. For the period from January 2015 through December 2015, we entered into fixed price swaps for 125,000 MMBtu per day at a weighted average price of $4.03. For the period from January 2016 through March 2016, we entered into fixed price swaps for 105,000 MMBtu per day at a weighted average price of $4.04. For April of 2016 we entered into fixed price swaps for 95,000 MMBtu per day at a weighted average price of $4.04. Under the 2014 contracts, we have hedged approximately 41% to 49% of our estimated 2014 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil. These forward sales contracts and fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815, "*Derivatives and Hedging*," and related pronouncements.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Risks Relating to Our Indebtedness

Our substantial level of indebtedness could adversely affect our business, financial condition, results of operations and prospects.

As of December 31, 2013, we had total indebtedness (net of associated accrued discount and premium) of approximately $299.2 million, including $297.2 million attributable to our senior notes, and borrowing base availability of $150.0 million under our secured revolving credit facility, under which no borrowings are outstanding.

Our outstanding indebtedness could have important consequences to you, including the following:

- our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations under any of our debt instruments, including restrictive covenants, could result in a default under our secured revolving credit facility or the senior note indenture;
- the restrictions imposed on the operation of our business by the terms of our debt agreements may hinder our ability to take advantage of strategic opportunities to grow our business;
- our ability to obtain additional financing for working capital, capital expenditures, debt service requirements, restructuring, acquisitions or general corporate purposes may be impaired, which could be exacerbated by further volatility in the credit markets;
- we must use a substantial portion of our cash flow from operations to pay interest on the Notes and our other indebtedness, which will reduce the funds available to us for operations and other purposes;
- our high level of indebtedness could place us at a competitive disadvantage compared to our competitors that may have proportionately less debt;
- our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate may be limited;
- our high level of indebtedness makes us more vulnerable to economic downturns and adverse developments in our business; and
- we may be vulnerable to interest rate increases, as our borrowings under our secured revolving credit facility are at variable interest rates.

Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations and prospects.

In addition, if we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, or interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest. More specifically, the lenders under our secured revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or litigation.

Servicing our indebtedness requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial indebtedness.

Our ability to make scheduled payments of the principal of, to pay interest on or to refinance our indebtedness, including the senior notes, depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as reducing or delaying capital expenditures, selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. In the absence of such cash flows, we could have substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. Our revolving credit facility and the indenture governing the senior notes restrict our ability to use the proceeds from asset sales. We may not be able to consummate those asset sales to raise capital or sell assets at prices that we believe are fair, and proceeds that we do receive may not be adequate to meet any debt service obligations then due. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at the time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on our financial condition.

Restrictive covenants in our secured revolving credit facility, the indenture governing the senior notes and in future debt instruments may restrict our ability to pursue our business strategies.

Our secured revolving credit facility and the indenture governing the senior notes limit, and the terms of any future indebtedness may limit, our ability, among other things, to:

- incur or guarantee additional indebtedness;
- make certain investments;
- declare or pay dividends or make distributions on our capital stock;
- prepay subordinated indebtedness;
- sell assets including capital stock of restricted subsidiaries;
- agree to payment restrictions affecting our restricted subsidiaries;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- enter into transactions with our affiliates;
- incur liens;
- engage in business other than the oil and gas business; and
- designate certain of our subsidiaries as unrestricted subsidiaries.

We may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants contained in our revolving credit facility and the indenture governing the senior notes. In addition, our revolving credit facility requires us to maintain certain financial ratios and tests. The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

A breach of any of these restrictive covenants could result in default under our revolving credit facility. If default occurs, the lenders under our revolving credit facility may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due and payable, which would result in an event of default under the indenture governing the senior notes. The lenders will also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If we are unable to repay outstanding borrowings when due, the lenders under our revolving credit facility will also have the right to proceed against the collateral granted to them to secure the indebtedness. If the indebtedness under our revolving credit facility and the senior notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Any significant reduction in our borrowing base under our revolving credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations, and we may not have sufficient funds to repay borrowings under our revolving credit facility if required as a result of a borrowing base redetermination.

Availability under our revolving credit facility is currently subject to a borrowing base of $150.0 million. The borrowing base is subject to scheduled semiannual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors. As of December 31, 2013, we had no outstanding borrowings under our revolving credit facility. We intend to continue borrowing under our revolving credit facility in the future. Any significant reduction in our borrowing base as a result of such borrowing base redeterminations or otherwise may negatively impact our liquidity and our ability to fund our operations and, as a result, may have a material adverse effect on our financial position, results of operation and cash flow. Further if, the outstanding borrowings under our revolving credit facility were to exceed the borrowing base as a result of any such redetermination, we would be required to repay the excess. We may not have sufficient funds to make such repayments. If we do not have sufficient funds and we are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We may still be able to incur substantial additional indebtedness in the future, which could further exacerbate the risks that we and our subsidiaries face.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of our revolving credit facility and the indenture governing the senior notes restrict, but in each case do not completely prohibit, us from doing so. As of December 31, 2013, our borrowing base under our revolving credit facility was set at $150.0 million and we had no borrowings outstanding under this facility. In addition, the indenture governing the senior notes allows us to issue additional notes under certain circumstances which will also be guaranteed by the guarantors. The indenture governing the senior notes also allows us to incur certain other additional secured debt and allows us to have subsidiaries that do not guarantee the senior notes and which may incur additional debt, which would be structurally senior to the senior notes. In addition, the indenture governing the senior notes does not prevent us from incurring other liabilities that do not constitute indebtedness. If we or a guarantor incur any additional indebtedness that ranks equally with the senior notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the senior notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

Our borrowings under our revolving credit facility expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our revolving credit facility. Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the eurodollar rates are elected, the eurodollar rates. As of December 31, 2013, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of December 31, 2013, we did not hedge our interest rate risk. An increase in our interest rate at the time we have variable interest rate borrowings outstanding under our revolving credit facility will increase our costs, which may have a material adverse effect on our results of operations and financial condition.

Risks Related to Our Common Stock

If our quarterly revenues and operating results fluctuate significantly, the price of our common stock may be volatile.

Our revenues and operating results may in the future vary significantly from quarter to quarter. If our quarterly results fluctuate, it may cause our stock price to be volatile. We believe that a number of factors could cause these fluctuations, including:

- changes in oil and natural gas prices;
- changes in production levels;
- changes in governmental regulations and taxes;
- geopolitical developments;
- the level of foreign imports of oil and natural gas; and
- conditions in the oil and natural gas industry and the overall economic environment.

Because of the factors listed above, among others, we believe that our quarterly revenues, expenses and operating results may vary significantly in the future and that period-to-period comparisons of our operating results are not necessarily meaningful. You should not rely on the results of one quarter as an indication of our future performance. It is also possible that in some future quarters, our operating results will fall below our expectations or the expectations of market analysts and investors. If we do not meet these expectations, the price of our common stock may decline significantly.

We do not currently pay dividends on our common stock and do not anticipate doing so in the future.

We have paid no cash dividends on our common stock, and we may not pay cash dividends on our common stock in the future. We intend to retain any earnings to fund our operations. Therefore, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the terms of our credit agreement prohibit the payment of any dividends to the holders of our common stock.

A change of control could limit our use of net operating losses.

As of December 31, 2013, we had a net operating loss, or NOL, carry forward of approximately $4.2 million for federal income tax purposes. Transfers of our stock in the future could result in an ownership change. In such a case, our ability to use the NOLs generated through the ownership change date could be limited. In general, the amount of NOLs we could use for any tax year after the date of the ownership change would be limited to the value of our stock (as of the ownership change date) multiplied by the long-term tax-exempt rate.

Future sales of our common stock may depress our stock price.

We have registered a substantial number of shares of our common stock under a registration statement filed with the SEC. Sales of these shares of our common stock in the public market or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, sales by certain of our stockholders of their shares could impair our ability to raise capital through the sale of common or preferred stock. As of February 21, 2014, there were 85,217,533 shares of our common stock issued and outstanding, excluding 503,636 shares of unvested restricted stock awarded under our Amended and Restated 2005 Stock Incentive Plan and 210,241 shares issuable upon exercise of outstanding options to purchase our common stock granted under our Amended and Restated 2005 Stock Incentive Plan.

We could issue preferred stock which could be entitled to dividend, liquidation and other special rights and preferences not shared by holders of our common stock or which could have anti-takeover effects.

We are authorized to issue up to 5,000,000 shares of preferred stock, par value $0.01 per share. Shares of preferred stock may be issued from time to time in one or more series as our board of directors, by resolution or resolutions, may from time to time determine each such series to be distinctively designated. The voting powers, preferences and relative, participating, optional and other special rights, and the qualifications, limitations or restrictions, if any, of each such series of preferred stock may differ from those of any and all other series of preferred stock at any time outstanding, and, subject to certain limitations of our certificate of incorporation and the Delaware General Corporation Law, or DGCL, our board of directors may fix or alter, by resolution or resolutions, the designation, number, voting powers, preferences and relative, participating, optional and other special rights, and qualifications, limitations and restrictions thereof, of each such series preferred stock. The issuance of any such preferred stock could materially adversely affect the rights of holders of our common stock and, therefore, could reduce the value of our common stock.

In addition, specific rights granted to future holders of preferred stock could be used to restrict our ability to merge with, or sell our assets to, a third party. The ability of our board of directors to issue preferred stock could discourage, delay or prevent a takeover of us, thereby preserving control of the company by the current stockholders.

The existence of some provisions in our organizational documents could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Additional information regarding our properties is included in Item 1. "Business" above and in Note 4 of the notes to our consolidated financial statements included in this report, which information is incorporated herein by reference.

Proved Oil and Natural Gas Reserves

SEC Rule-Making Activity

In December 2008, the SEC released its final rule for “Modernization of Oil and Gas Reporting.” These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required unless contractual arrangements designate the price to be used. Other significant amendments included the following:

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.
- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.

- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We adopted the rules effective December 31, 2009, as required by the SEC.

Evaluation and Review of Reserves.

Reserve estimates at December 31, 2013 were prepared by NSAI with respect to our WCBB, Hackberry and Niobrara fields (16% of our proved reserves at December 31, 2013), by Ryder Scott with respect to our assets in the Utica Shale in Eastern Ohio (84% of our proved reserves at December 31, 2013) and by our personnel with respect to our overriding royalty and non-operated interests (less than 1% of our proved reserves at December 31, 2013).

NSAI and Ryder Scott are independent petroleum engineering firms. Copies of their summary reserve reports are included as Exhibit 99.1 and 99.2, respectively, to this Annual Report on Form 10-K. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI and Ryder Scott, our independent reserve engineers, to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our WCBB, Hackberry and Niobrara fields and our assets in the Utica Shale. Our internal technical team members meet with NSAI and Ryder Scott periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI and Ryder Scott for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our proved reserves attributable to our other minority interests are prepared internally by our internal staff of petroleum engineers and geoscience professionals. Our Vice President of Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 35 years of reservoir and operations experience and our geophysical staff has over 60 years combined industry experience. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

Our proved reserve estimates are prepared in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our experienced reservoir engineers or under their direct supervision;
- review by our reservoir engineering department of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our reservoir engineering department to our Chief Executive Officer; and
- verification of property ownership by our land department.

The following table sets forth our estimated proved reserves at December 31, 2013, 2012 and 2011:

	Year Ended December 31,								
	2013			2012			2011		
	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)
Proved developed	5,609	94,552	3,527	5,175	18,482	44	6,780	6,152	705
Proved undeveloped	2,737	51,894	2,148	2,931	15,289	101	7,174	9,576	2,086
Total (1)	8,346	146,446	5,675	8,106	33,771	145	13,954	15,728	2,791

	Year Ended December 31,		
	2013	2012	2011
Total net proved oil and natural gas reserves (MBOE) (1)	38,429	13,879	19,367
PV-10 value (in millions) (2)	$ 696.9	$ 436.8	$ 490.5
Standardized measure (in millions) (3)	$ 578.5	$ 348.6	$ 376.7

(1) Estimates of reserves as of year-end 2013, 2012 and 2011 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2013, 2012 and 2011, respectively, in accordance with revised guidelines of the SEC applicable to reserves estimates as of year-end 2013, 2012 and 2011. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

(2) Represents present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proven reserves. The estimated future net revenues set forth above were determined by using reserve quantities of proved reserves and the periods in which they are expected to be developed and produced based on certain prevailing economic conditions. The estimated future production in our reserve reports for the years ended December 31, 2013, 2012 and 2011 is priced based on the 12-month unweighted arithmetic average of the first-day-of-the month price for the period January through December of the applicable year, using $96.78 per barrel and $3.67 per MMBtu for 2013, $91.32 per barrel and $2.76 per MMBtu for 2012 and $96.19 per barrel and $4.12 per MMBtu for 2011, and in each case adjusted by lease for transportation fees and regional price differentials.

PV-10 is a non-GAAP measure because it excludes income tax effects. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. PV-10 is not a measure of financial or operating performance under GAAP. PV-10 should not be considered as an alternative to the standardized measure as defined under GAAP. We have included a reconciliation of PV-10 to the most directly comparable GAAP measure-standardized measure of discounted future net cash flows. The following table reconciles the standardized measure of future net cash flows to the PV-10 value:

	December 31,		
	2013	2012	2011
		(In thousands)	
Standardized measure of discounted future net cash flows	$ 578,466	$ 348,641	$ 376,681
Add: Present value of future income tax discounted at 10%	118,445	88,206	113,791
PV-10 value	$ 696,911	$ 436,847	$ 490,472

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

The above table does not include proved reserves net to our interest in Diamondback, Tatex II, Tatex III or Grizzly. For further discussion of our interest in Tatex II, Tatex III and Grizzly, see Item 1. "*Business-Our Equity Investments*."

The foregoing reserves are all located within the continental United States. Reserve engineering is a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. See Item 1A. "*Risk Factors*" contained elsewhere in this Form 10-K. We have not filed any estimates of total, proved net oil or gas reserves with any federal authority or agency other than the SEC since the beginning of our last fiscal year.

Additional information regarding estimates of proved reserves, proved developed reserves and proved undeveloped reserves, or PUDs, at December 31, 2013, 2012 and 2011 and changes in proved reserves during the last three years are contained in the Supplemental Information on Oil and Gas Exploration and Production Activities, or Supplemental Information, in Note 19 to our consolidated financial statements included in this report. Also contained in the Supplemental Information are our estimates of future net cash flows and discounted future net cash flows from proved reserves. Additional information regarding our proved reserves can be found in Item 7. "*Management's Discussion and Analysis of Financial Condition and Results of Operations-Results of Operations*" and "*-Critical Accounting Policies and Estimates*" included in this report.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2013, our proved undeveloped reserves totaled 2,737 MBOE of oil, 51,894 MMcf of natural gas and 2,148 MBOE of NGLs, for a total of 13,534 MBOE. Approximately 87% of our PUDs at year-end 2013 were located in our Utica field, 6% were located in WCBB, 5% were located in our East Hackberry field and 1% of our PUDs were located in our Niobrara field. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Changes in PUDs that occurred during 2013 were primarily due to:

- Additions of 8,331 MBOE attributable to 2013 acquisitions and extensions in our Utica field and additions of 403 MBOE attributable to 2013 extensions in our Louisiana fields;
- Conversion of approximately 341 MBOE attributable to PUDs into proved developed reserves;
- Downward revisions to estimates of approximately 213 MBOE; and
- Exclusion of 225 MBOE attributable to 13 PUD locations that were not scheduled to be drilled within the next five years.

Costs incurred relating to the development of PUDs were approximately $43.5 million in 2013. Estimated future development costs relating to the development of PUDs are projected to be approximately $135.4 million in 2014, $68.7 million in 2015, $8.5 million in 2016 and $8.5 million in 2017.

All PUD drilling locations are scheduled to be drilled prior to the end of 2018.

As of December 31, 2013, 7% of our total proved reserves were classified as proved developed non-producing.

Production, Prices, and Production Costs

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2013	2012	2011
Production Volumes:			
Oil (MBbls)	2,317	2,323	2,128
Gas (MMcf)	8,891	1,108	878
Natural gas liquids (MGal)	13,416	2,714	2,468
Oil equivalents (MBOE)	4,118	2,573	2,333
Average Prices:			
Oil (per Bbl)	$ 96.74 (1)	$ 104.46 (1)	$ 104.33 (1)
Gas (per Mcf)	$ 2.36 (1)	$ 2.91	$ 4.37
Natural gas liquids (per Gal)	$ 1.27	$ 0.98	$ 1.25
Oil equivalents (per BOE)	$ 63.68	$ 96.63	$ 98.13
Production Costs:			
Average production costs (per BOE)	$ 6.48	$ 9.45	$ 8.96
Average production taxes and midstream costs (per BOE)	$ 9.22	$ 11.43	$ 11.29
Total production and midstream costs and production taxes (per BOE)	$ 15.70	$ 20.88	$ 20.25

(1) Includes various derivative contracts at a weighted average price of:

		Per barrel
January – December 2013	$	100.90
January – December 2012	$	108.31
January – December 2011	$	86.96

		Per MMBtu
January – December 2013	$	4.00

Excluding the effect of fixed price swaps, the average price for 2013 would have been $104.51 per barrel of oil, $3.73 per Mcf of gas and $70.99 per BOE. The total volume hedged for 2013 represented approximately 48% of our total sales volumes for the year. Excluding the effect of fixed price swaps, the average oil price for 2012 would have been $106.11 per barrel of oil and $98.12 per BOE. The total volume hedged for 2012 represented approximately 46% of our total sales volumes for the year. Excluding the effect of fixed price swap contracts, the average oil price for 2011 would have been $107.13 per barrel of oil and $100.68 per BOE. The total volume hedged for 2011 represented approximately 31% of our total sales volumes for the year.

The following table provides a summary of our production, average sales prices and average production costs for oil and gas fields containing 15% or more of our total proved reserves as of December 31, 2013:

	Year Ended December 31,					
		2013		2012		2011
WCBB						
Net Production						
Oil (MBbls)		1,251		1,126		1,258
Gas (MMcf)		77		260		237
NGL (Mgal)		—		—		—
Total (MBOE)		1,264		1,169		1,298
Average Sales Price:						
Oil (per Bbl)	$	93.80	$	105.19	$	104.49
Gas (per Mcf)	$	3.55	$	2.89	$	4.16
NGL (per Gal)	$	—	$	—	$	—
Average Production Cost (per BOE)	$	10.11	$	9.66	$	8.71
Utica Shale						
Net Production						
Oil (MBbls)		315		25		—
Gas (MMcf)		8,439		365		—
NGL (Mgal)		13,384		80		—
Total (MBOE)		2,040		87		—
Average Sales Price:						
Oil (per Bbl)	$	83.67	$	78.21	$	—
Gas (per Mcf)	$	2.29	$	2.99	$	—
NGL (per Gal)	$	1.27	$	1.56	$	—
Average Production Cost (per BOE)	$	3.57	$	8.30	$	—

Productive Wells and Acreage

The following table presents our total gross and net productive and non-productive wells, expressed separately for oil and gas, and the total gross and net developed and undeveloped acres as of December 31, 2013.

Field	NRI/WI (1) Percentages	Productive Oil Wells (2) Gross	Productive Oil Wells (2) Net	Productive Gas Wells Gross	Productive Gas Wells Net	Non-Productive Oil Wells Gross	Non-Productive Oil Wells Net	Non-Productive Gas Wells Gross	Non-Productive Gas Wells Net	Developed Acreage (3) Gross	Developed Acreage (3) Net	Undeveloped Acreage Gross	Undeveloped Acreage Net
Utica Shale (4)	51.61/63.9	27	17	11	7	—	—	1	1	10,627	8,694	141,639	134,541
West Cote Blanche Bay Field (5)	80.108/100	110	110	—	—	183	183	18	18	5,668	5,668	—	—
E. Hackberry Field (6)	80.309/100	47	47	—	—	86	86	—	—	3,931	3,931	581	581
W. Hackberry Field	83.333/100	4	4	—	—	19	19	—	—	1,192	1,192	—	—
Niobrara Formation (7)	36.77/47.85	6	3	—	—	1	1	—	—	3,448	1,724	11,680	5,757
Bakken Formation (8)	2.16/1.795	13	0.3	—	—	—	—	—	—	1,862	163	3,505	701
Overrides/ Royalty Non-operated	Various	266	0.45	—	—	2	0.06	—	—	—	—	—	—
Total		473	181.75	11	7	291	289.06	19	19	26,728	21,372	157,405	141,580

(1) Net Revenue Interest (NRI)/Working Interest (WI).
(2) Includes three gross and net wells at WCBB that are producing intermittently.
(3) Developed acres are acres spaced or assigned to productive wells. Approximately 13% of our acreage is developed acreage and has been perpetuated by production.
(4) None of our Utica acreage is scheduled to expire until 2015, at which time 32% of our total Utica Shale undeveloped acreage as of December 31, 2013 will be subject to expiration, with 68% of such acreage expiring thereafter, although our Utica Shale leases generally grant us the right to extend these leases for an additional five-year period. NRI/WI is from wells that have been drilled or in which we have elected to participate.
(5) We have a 100% working interest (80.108% average NRI) from the surface to the base of the 13900 Sand which is located at 11,320 feet. Below the base of the 13900 Sand, we have a 40.40% non-operated working interest (29.95% NRI).
(6) NRI shown is for producing wells.
(7) The leases relating to our Niobrara Formation acreage will expire at the end of their respective primary terms unless the applicable leases are renewed or extended, we have commenced the necessary operations required by the terms of the applicable leases or we have obtained actual production from acreage subject to the applicable leases, in which event they will remain in effect until the cessation of production. Leases representing 33%, 4%, 22%, 4% and 37% of our total Niobrara undeveloped acreage are currently scheduled to expire in 2014, 2015, 2016, 2017 and thereafter, respectively.
(8) NRI/WI is from wells that have been drilled or in which we have elected to participate.

Completed and Present Drilling and Recompletion Activities

The following table sets forth information with respect to wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Recompletions:						
Productive	150	150	92	92	100	96
Dry	—	—	1	0.5	—	—
Total	150	150	93	92.5	100	96
Development:						
Productive	132	67	70	57	82	57
Dry	2	2	8	7	3	3
Total	134	69	78	64	85	60
Exploratory:						
Productive	3	2.7	19	6	1	1
Dry	—	—	—	—	—	—
Total	3	2.7	19	6	1	1

Title to Oil and Natural Gas Properties

It is customary in the oil and natural gas industry to make only a cursory review of title to undeveloped oil and natural gas leases at the time they are acquired and to obtain more extensive title examinations when acquiring producing properties. In future acquisitions, we will conduct title examinations on material portions of such properties in a manner generally consistent with industry practice. Certain of our oil and natural gas properties may be subject to title defects, encumbrances, easements, servitudes or other restrictions, none of which, in management's opinion, will in the aggregate materially restrict our operations.

ITEM 3. LEGAL PROCEEDINGS

In September 2013, we entered into a compliance agreement with the Ohio Division of Oil and Gas Resources Management, or the Division, concerning aspects of our operations at seven drilling sites in Ohio. See "Item 1A. Risk Factors" for a description of this matter, the compliance agreement and certain risks involved.

The Louisiana Department of Revenue, or LDR, is disputing our severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that we paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes we would have had to pay had we paid severance taxes on the oil at the contracted market rates only. We have denied any liability to the LDR for underpayment of severance taxes and have maintained that we were entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. We have maintained our right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against us seeking $2.3 million in severance taxes, plus interest and court costs. We filed a response denying any liability to the LDR for underpayment of severance taxes. The LDR had taken no further action on this lawsuit since filing its petition other than propounding discovery requests to which we have responded. Since serving discovery requests on the LDR and receiving the LDR's responses in 2012, there has been no further activity on the case and no trial date has been set.

In December 2010, the LDR filed two identical lawsuits against us in different venues to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney’s fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the lawsuit filed by the LDR in 2009 discussed in the paragraph above, we deny all liability and will vigorously defend the lawsuit. The cases are in the early stages, and we have not yet filed a response to the recent lawsuits. The LDR filed motions to stay the lawsuits before we filed any responsive pleadings. Although there had been no activity on either of these lawsuits for years, in September 2013, the LDR moved to dismiss one of the identical lawsuits it filed in the 19th Judicial District Court in 2010, amended the petition it filed in the 15th Judicial District Court in 2010, and served discovery requests on us. The LDR asserts that we underpaid severance taxes by nearly $12 million from 2007 to 2010. The LDR also asserts that we owe an additional $4.4 million and may be subject to additional penalties. The LDR's claims are still in their infancy and there has been no formal discovery. In February 2014, the LDR has asserted that Gulfport owes additional severance taxes for the cash settlements it received to terminate forward sales contracts. We maintain that the LDR's claims are not well-grounded in fact or law and intend to aggressively defend the lawsuits.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for surface contamination in areas where the defendants operated in an action entitled Reeds et al. v. BP American Production Company et al.,38th Judicial District. No. 10-18714. The plaintiffs' original petition for damages, which did not name us as a defendant, alleges that the plaintiffs' property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. The plaintiffs allege that the defendants conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, we were served with a copy of the plaintiffs' first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including us, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. In addition to us, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, we filed a pleading challenging the legal sufficiency of the petitions on several grounds and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by us and similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, we and numerous defendants re-urged our pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. We noticed our intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. We filed our supervisory writ, which was denied by the Louisiana Third Circuit Court of Appeal and the Louisiana Supreme Court. The parties engaged in a non-binding mediation in July 2013 to discuss settlement and discussions are on-going. At this time, the parties are continuing to conduct discovery. The trial date has been continued to July 2014.

Due to the current stages of the LDR and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. Adverse decisions in one or more of the above matters could have a material adverse effect on our financial condition or results of operations and management cannot determine the amount of loss, if any, that may result.

We have been named as a defendant in various other lawsuits related to our business. The resolution of these matters is not expected to have a material adverse effect on our financial condition or results of operations in future periods.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Price Range of Common Stock

Our common stock is quoted on the NASDAQ Global Select Market under the symbol "GPOR." The following table sets forth the high and low sale prices of our common stock for the periods presented:

	Price Range of Common Stock	
	High	Low
2012		
First Quarter	$ 37.63	$ 27.66
Second Quarter	29.66	15.79
Third Quarter	33.11	18.17
Fourth Quarter	40.73	28.94
2013		
First Quarter	$ 47.19	$ 35.24
Second Quarter	54.07	43.98
Third Quarter	64.73	46.85
Fourth Quarter	69.81	53.93
2014		
First Quarter (through February 27, 2014)	$ 65.78	$ 52.28

On February 27, 2014, the last reported sale price of our common stock on the NASDAQ Global Select Market was $62.13.

Unregistered Sales of Equity Securities and Use of Proceeds

None.

Repurchases of Equity Securities

None.

Holders of Record

At the close of business on February 25, 2014, there were 318 stockholders of record holding 85,217,533 shares of our outstanding common stock. There were approximately 36,191 beneficial owners of our common stock as of February 25, 2014.

Dividend Policy

We have never paid dividends on our common stock. We currently intend to retain all earnings to fund our operations. Therefore, we do not intend to pay any cash dividends on the common stock in the foreseeable future. In addition, the terms of our credit facility prohibit the payment of any dividends to the holders of our common stock.

ITEM 6. SELECTED FINANCIAL DATA

You should read the following selected consolidated financial data in conjunction with "Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations"* and the consolidated financial statements and the related notes appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2013, December 31, 2012 and December 31, 2011 and the selected consolidated balance sheet data at December 31, 2013 and December 31, 2012 are derived from our audited consolidated financial statements appearing elsewhere in this report. The selected consolidated statements of operations data for the fiscal years ended December 31, 2010 and December 31, 2009 and the selected consolidated balance sheet data at December 31, 2011, December 31, 2010 and December 31, 2009 are derived from our audited consolidated financial statements that are not included in this report. The historical data presented below is not indicative of future results. We did not pay any cash dividends on our common stock during any of the periods set forth in the following table.

	Fiscal Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands, except share data)				
Selected Consolidated Statements of Operations Data:					
Revenues	$ 262,753	$ 248,926	$ 229,254	$ 127,921	$ 85,968
Costs and expenses:					
Lease operating expenses	26,703	24,308	20,897	17,614	16,316
Production taxes	26,933	28,957	26,054	13,823	9,673
Midstream transportation, processing and marketing	11,030	443	279	143	124
Depreciation, depletion and amortization	118,880	90,749	62,320	38,907	29,225
General and administrative	22,519	13,808	8,074	6,063	4,992
Accretion expense	717	698	666	617	582
Loss (gain) on sale of assets	508	(7,300)	—	—	—
	207,290	151,663	118,290	77,167	60,912
Income from Operations	55,463	97,263	110,964	50,754	25,056
Other (Income) Expense:					
Interest expense	17,490	7,458	1,400	2,761,000	2,309,000
Insurance recoveries	—	—	—	—	(1,050)
Interest income	(297)	(72)	(186)	(387)	(564)
(Income) loss from equity method investments	(213,058)	(8,322)	1,418	977	706
	(195,865)	(936)	2,632	3,351	1,401
Income from Continuing Operations before Income Taxes	251,328	98,199	108,332	47,403	23,655
Income Tax Expense (Benefit)	98,136	26,363	(90)	40	28
Income from Continuing Operations	153,192	71,836	108,422	47,363	23,627
Discontinued Operations:					
Loss on disposal of Belize properties, net of tax	—	3,465	—	—	—
Net Income Available to Common Stockholders	$ 153,192	$ 68,371	$ 108,422	$ 47,363	$ 23,627
Net Income Per Common Share—Basic:	$ 1.98	$ 1.22	$ 2.22	$ 1.08	$ 0.55
Net Income Per Common Share—Diluted:	$ 1.97	$ 1.21	$ 2.20	$ 1.07	$ 0.55

	At December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Selected Consolidated Balance Sheet Data:					
Total assets	$ 2,693,136	$ 1,578,368	$ 691,158	$ 319,693	$ 227,344
Total debt, including current maturity	$ 299,187	$ 299,038	$ 2,283	$ 51,917	$ 52,428
Total liabilities	$ 642,898	$ 451,960	$ 58,808	$ 108,637	$ 102,293
Stockholders' equity	$ 2,050,238	$ 1,126,408	$ 632,350	$ 125,051	$ 114,101

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

The following discussion and analysis should be read in conjunction with the consolidated financial statements and related notes included elsewhere in this Annual Report on Form 10-K. This discussion contains forward-looking statements reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in Item 1A. "Risk Factors" and the section entitled "Cautionary Note Regarding Forward-Looking Statements" appearing elsewhere in this Annual Report on Form 10-K.

Overview

We are an independent oil and natural gas exploration and production company focused on the exploration, exploitation, acquisition and production of crude oil, natural gas liquids and natural gas in the United States. Our corporate strategy is to internally identify prospects, acquire lands encompassing those prospects and evaluate those prospects using subsurface geology and geophysical data and exploratory drilling. Using this strategy, we have developed an oil and natural gas portfolio of proved reserves, as well as development and exploratory drilling opportunities on high potential conventional and unconventional oil and natural gas prospects. Our principal properties are located in the Utica Shale in Eastern Ohio and along the Louisiana Gulf Coast in the West Cote Blanche Bay, or WCBB, and Hackberry fields. In addition, we have producing properties in the Niobrara Formation of Northwestern Colorado and the Bakken Formation. We also hold a significant acreage position in the Alberta oil sands in Canada through our interest in Grizzly Oil Sands ULC, or Grizzly, an equity interest in Diamondback Energy, Inc., or Diamondback, a NASDAQ Global Select Market listed company to which we contributed our Permian Basin oil and natural gas interests in October 2012 immediately prior to Diamondback's initial public offering, or the Diamondback IPO, and interests in entities that operate in Southeast Asia, including the Phu Horm gas field in Thailand. We seek to achieve reserve growth and increase our cash flow through our annual drilling programs.

2013 and 2014 Year to Date Highlights

- Oil and natural gas revenues increased 5% to $262.2 million for the year ended December 31, 2013 from $248.6 million for the year ended December 31, 2012.
- Production increased 60% to approximately 4,118,131 BOE for the year ended December 31, 2013 from approximately 2,572,618 BOE for the year ended December 31, 2012.
- During 2013, we drilled 98 gross (79 net) wells, participated in an additional 49 gross (2.6 net) wells that were drilled by other operators on our Utica Shale acreage and recompleted 150 gross and net wells. Of our 98 new wells drilled at year end 2013, 64 were completed as producing wells, two were non-productive, 14 were waiting on completion, nine were waiting on a horizontal rig and nine were drilling.
- On February 26, 2014, we entered into a binding letter of intent with Rhino to acquire approximately 8,200 net acres in the Utica Shale of Eastern Ohio and approximately 1,000 BOEPD of production during January 2014 for a total purchase price of $185.0 million, subject to closing adjustments. We are the operator of substantially all of this acreage.
- Through February 27, 2014, after giving pro forma effect to our pending acquisition disclosed above, we would have acquired leasehold interests in approximately 167,700 gross (165,400 net) acres in the Utica Shale in Eastern Ohio. During 2013, we drilled 52 gross (39 net) wells on our Utica Shale acreage and, as of February 14, 2014, we had spud six gross (five net) wells during 2014, all of which were being drilled.
- In June and November 2013, we sold shares of our Diamondback common stock in underwritten public offerings for an aggregate of $192.7 million in net proceeds. As of December 31, 2013, we owned approximately 7.2% of Diamondback's outstanding common stock.
- In February 2013, we completed an underwritten public offering of an aggregate of 8,912,500 shares of our common stock and received net proceeds of approximately $325.8 million. We used approximately $220.4 million to fund our acquisition of approximately 22,000 net acres in the Utica Shale in Eastern Ohio and the remaining net proceeds for general corporate purposes, which included funding a portion of our 2013 capital development plan.
- In November 2013, we completed an underwritten public offering of an aggregate of 7,475,000 shares of our common stock and received net proceeds of approximately $408.0 million. We have used, and intend to continue to use, the net proceeds from this equity offering for general corporate purposes, which may include expenditures associated with our 2014 drilling program and additional acreage acquisitions in the Utica Shale.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP. The preparation of these consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates including those related to oil and natural gas properties, revenue recognition, income taxes and commitments and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements:

Oil and Natural Gas Properties. We use the full cost method of accounting for oil and natural gas operations. Accordingly, all costs, including non-productive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and natural gas properties, are capitalized. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the prior twelve months, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and natural gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves. Oil and natural gas properties not subject to amortization consist of the cost of undeveloped leaseholds and totaled $950.6 million at December 31, 2013 and $626.3 million at December 31, 2012. These costs are reviewed quarterly by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. Factors considered by management in its impairment assessment include our drilling results and those of other operators, the terms of oil and natural gas leases not held by production and available funds for exploration and development.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas properties are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for the prior twelve months of the applicable year beginning with 2009, adjusted for any contract provisions or financial derivatives, if any, that hedge our oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required. Ceiling test impairment can give us a significant loss for a particular period; however, future depletion expense would be reduced. A decline in oil and gas prices may result in an impairment of oil and gas properties. For instance, as a result of the drop in commodity prices on December 31, 2008 and subsequent reduction in our proved reserves, we recognized a ceiling test impairment of $272.7 million for the year ended December 31, 2008. If prices of oil, natural gas and natural gas liquids decline, we may be required to further write down the value of our oil and gas properties, which could negatively affect our results of operations. No ceiling test impairment was required for the year ended December 31, 2013.

Asset Retirement Obligations. We have obligations to remove equipment and restore land at the end of oil and gas production operations. Our removal and restoration obligations are primarily associated with plugging and abandoning wells and associated production facilities.

We account for abandonment and restoration liabilities under FASB ASC 410 which requires us to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, we increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

The fair value of the liability associated with these retirement obligations is determined using significant assumptions, including current estimates of the plugging and abandonment or retirement, annual inflations of these costs, the productive life of the asset and our risk adjusted cost to settle such obligations discounted using our credit adjustment risk free interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to the carrying amount of the related long-lived asset, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of our oil and natural gas assets, the costs to ultimately retire these assets may vary significantly from previous estimates.

Oil and Gas Reserve Quantities. Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Netherland, Sewell & Associates, Inc., Ryder Scott Company, L.P. and to a lesser extent our personnel have prepared reserve reports of our reserve estimates at December 31, 2013 on a well-by-well basis for our properties.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows derived from these reserve estimates have been prepared in accordance with the guidelines of the Securities and Exchange Commission, or SEC. The accuracy of our reserve estimates is a function of many factors including the following:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. Therefore, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Income Taxes. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized in the year in which realization becomes determinable. Periodically, management performs a forecast of its taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established, if in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2013, a valuation allowance of $4.7 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized.

Revenue Recognition. We derive almost all of our revenue from the sale of crude oil and natural gas produced from our oil and gas properties. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment on substantially all of these sales from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers that month and the price we will receive. Variances between our estimated revenue and actual payment received for all prior months are recorded at the end of the quarter after payment is received. Historically, our actual payments have not significantly deviated from our accruals.

Investments—Equity Method. Investments in entities greater than 20% and less than 50% and/or investments in which we have significant influence are accounted for under the equity method. Under the equity method, our share of investees' earnings or loss is recognized in the statement of operations. In accordance with FASB ASC 825*, "Financial Instruments,"* we have elected the fair value option of accounting for our equity method investment in Diamondback's stock. At the end of each reporting period, the quoted closing market price of Diamondback's stock is multiplied by the total shares owned by us and the resulting gain or loss is recognized in (income) loss from equity method investments in the consolidated statements of operations.

We review our investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, we recognize an impairment provision. There was no impairment of equity method investments at December 31, 2013 or 2012.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. We are involved in certain litigation for which the outcome is uncertain. Changes in the certainty and the ability to reasonably estimate a loss amount, if any, may result in the recognition and subsequent payment of legal liabilities.

Derivative Instruments and Hedging Activities. We seek to reduce our exposure to unfavorable changes in oil and natural gas prices by utilizing energy swaps and collars, or fixed-price contracts. We follow the provisions of FASB ASC 815, "*Derivatives and Hedging*," as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value. We estimate the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and our realized prices, time to maturity and credit risk. The values reported in the financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. We recognize any change in fair value resulting from ineffectiveness immediately in earnings.

See "Item 7. Commodity Price Risk" for a summary of our fixed price swaps and swaptions in place as of December 31, 2013.

RESULTS OF OPERATIONS

Results of Operations

The markets for oil and natural gas have historically been, and will continue to be, volatile. Prices for oil and natural gas may fluctuate in response to relatively minor changes in supply and demand, market uncertainty and a variety of factors beyond our control.

The following table presents our production volumes, average prices received and average production costs during the periods indicated:

	2013		2012		2011	
Production Volumes:						
Oil (MBbls)	2,317		2,323		2,128	
Gas (MMcf)	8,891		1,108		878	
Natural gas liquids (MGal)	13,416		2,714		2,468	
Oil equivalents (MBOE)	4,118		2,573		2,333	
Average Prices:						
Oil (per Bbl)	$ 96.74	(1)	$ 104.46	(1)	$ 104.33	(1)
Gas (per Mcf)	$ 2.36	(1)	$ 2.91		$ 4.37	
Natural gas liquids (per Gal)	$ 1.27		$ 0.98		$ 1.25	
Oil equivalents (per BOE)	$ 63.68		$ 96.63		$ 98.13	
Production Costs:						
Average production costs (per BOE)	$ 6.48		$ 9.45		$ 8.96	
Average production taxes and midstream costs (per BOE)	$ 9.22		$ 11.43		$ 11.29	
Total production and midstream costs and production taxes (per BOE)	$ 15.70		$ 20.88		$ 20.25	

(1) Includes various derivative contracts at a weighted average price of:

	Per barrel
January – December 2013	$ 101.90
January – December 2012	$ 108.31
January – December 2011	$ 86.96

	Per MMBtu
January – December 2013	$ 4.00

Excluding the net effect of fixed price swaps, the average price for 2013 would have been $104.51 per barrel of oil, $3.73 per Mcf of gas and $70.99 per BOE. The total volume hedged for 2013 represented approximately 48% of our total sales volumes for the year. Excluding the net effect of fixed price swap contracts, the average oil price for 2012 would have been $106.11 per barrel of oil and $98.12 per BOE. The total volume hedged for 2012 represented approximately 46% of our total sales volumes for the year. Excluding the net effect of forward sales contracts, the average oil price for 2011 would have been $107.13 per barrel of oil and $100.68 per BOE. The total volume hedged for 2011 represented approximately 31% of our total sales volumes for the year.

From 2012 to 2013, our net equivalent oil production increased 60% from 2,572,618 BOE to 4,118,131 BOE primarily as a result of the development of our Utica Shale acreage. From 2011 to 2012, our net equivalent oil production also increased 10% from 2,333,208 BOE to 2,572,618 BOE due to the results of our 2012 drilling and recompletion activities. We currently estimate that our 2014 production will be between 18,250,000 and 21,900,000 BOE. However, our actual production may be different due to changes in our currently anticipated drilling and recompletion activities, changing economic climate, adverse weather conditions or other unforeseen events.

Comparison of the Years Ended December 31, 2013 and December 31, 2012

We reported net income of $153.2 million for the year ended December 31, 2013 as compared to $68.4 million for the year ended December 31, 2012 . This 124% increase in period-to-period net income was due primarily to $220.1 million of income recognized from our equity method investment in Diamondback and a 60% increase in net production to 4,118,131 BOE from 2,572,618, partially offset by a 34% decrease in realized BOE prices to $63.68 from $96.63, a $2.4 million increase in lease operating expenses, a $10.6 million increase in midstream transportation, processing and marketing expenses, an $8.7 million increase in general and administrative expenses, a $10.0 million increase in interest expense and a $71.8 million increase in income tax expense for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Oil and Gas Revenues. For the year ended December 31, 2013, we reported oil and natural gas revenues of $262.2 million as compared to oil and natural gas revenues of $248.6 million during 2012. This $13.6 million, or 5%, increase in revenues was primarily attributable to a 60% increase in net production to 4,118,131 BOE from 2,572,618 BOE, partially offset by a 34% decrease in realized BOE prices to $63.68 from $96.63, for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2013 and December 31, 2012:

	Year Ended December 31,	
	2013	2012
Oil production volumes (MBbls)	2,317	2,323
Gas production volumes (MMcf)	8,891	1,108
Natural gas liquids production volumes (MGal)	13,416	2,714
Oil equivalents (MBOE)	4,118	2,573
Average oil price (per Bbl)	$ 96.74	$ 104.46
Average gas price (per Mcf)	$ 2.36	$ 2.91
Average natural gas liquids (per Gal)	$ 1.27	$ 0.98
Oil equivalents (per BOE)	$ 63.68	$ 96.63

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $26.7 million for the year ended December 31, 2013 from $24.3 million for the year ended December 31, 2012. This increase was mainly the result of an increase in expenses related to property taxes, compressor rentals, compressor repairs and maintenance, contract pumpers, environmental services, insurance expense, and salt water disposal.

Production Taxes. Production taxes decreased to $26.9 million for the year ended December 31, 2013 from $29.0 million for 2012. This decrease was primarily related to changes in our product mix and production location.

Midstream Transportation, Processing and Marketing Expenses. Midstream transportation, processing and marketing expenses increased by $10.6 million to $11.0 million for the year ended December 31, 2013 from $0.4 million for 2012. This increase was primarily the result of midstream expenses related to our production volumes in the Utica Shale resulting from our 2013 drilling activities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $118.9 million for the year ended December 31, 2013, and consisted of $118.1 million in depletion of oil and natural gas properties and $0.8 million in depreciation of other property and equipment, as compared to total DD&A expense of $90.7 million for 2012. This increase was due to an increase in our full cost pool as a result of our capital activities as well as an increase in our production, partially offset by an increase in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $22.5 million for the year ended December 31, 2013 from $13.8 million for the year ended December 31, 2012. This $8.7 million increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, corporate fees, consulting fees and fees for auditing services and a reduction in administrative services reimbursements under the acquisition team agreement, partially offset by an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at $0.7 million for the years ended December 31, 2013 and 2012.

Interest Expense. Interest expense increased to $17.5 million for the year ended December 31, 2013 from $7.5 million for the year ended December 31, 2012 due largely to a full year of interest on our 7.75% Senior Notes due 2020. During 2013, we had no debt outstanding under our revolving credit facility as compared to total weighted average debt outstanding under our revolving credit facility of $45.0 million in 2012, which bore a weighted average interest rate of 2.85%. On October 17, 2012, we issued $250.0 million aggregate principal amount of our 7.75% Senior Notes due 2020, a portion of the proceeds from which was used to repay all outstanding borrowings under our revolving credit facility. On December 21, 2012, we issued an additional $50.0 million aggregate principal amount of our 7.75% Senior Notes due 2020. Additionally, we capitalized approximately $7.1 million in interest expense to undeveloped oil and natural gas properties during the year ended December 31, 2013 as a result of increased interest costs incurred on our 7.75% Senior Notes. We did not capitalize any interest costs for the year ended December 31, 2012.

Income Taxes. As of December 31, 2013, we had a net operating loss carry forward of approximately $4.2 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2013, a valuation allowance of $4.7 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized. We recognized an income tax expense from continuing operations of $98.1 million for the year ended December 31, 2013.

Comparison of the Years Ended December 31, 2012 and December 31, 2011

We reported net income of $68.4 million for the year ended December 31, 2012 as compared to net income of $108.4 million for the year ended December 31, 2011. This 37% decrease in period-to-period net income was due primarily to a 2% decrease in realized BOE prices to $96.63 for the year ended December 31, 2012, a 16% increase in lease operating expenses, a 71% increase in general and administrative expenses, an 11% increase in production taxes, an approximately $6.0 million increase in interest expense, a $3.5 million loss on the disposal of our Belize properties, net of tax, and a $24.2 million increase in income taxes from continuing and discontinued operations, partially offset by a 10% increase in net production to 2,572,618 BOE, a gain on sale of assets of $7.3 million and income from equity method investments of $8.3 million.

Oil and Gas Revenues. For the year ended December 31, 2012, we reported oil and natural gas revenues of $248.6 million as compared to oil and natural gas revenues of $229.0 million during 2011. This $19.6 million, or 9%, increase in revenues was primarily attributable to a 10% increase in net production to 2,572,618 BOE from 2,333,208 BOE, partially offset by a 2% decrease in realized BOE prices to $96.63 from $98.13, for the year ended December 31, 2012 as compared to the year ended December 31, 2011.

The following table summarizes our oil and natural gas production and related pricing for the years ended December 31, 2012 and December 31, 2011:

	Year Ended December 31,	
	2012	2011
Oil production volumes (MBbls)	2,323	2,128
Gas production volumes (MMcf)	1,108	878
Natural gas liquids production volumes (MGal)	2,714	2,468
Oil equivalents (MBOE)	2,573	2,333
Average oil price (per Bbl)	$ 104.46	$ 104.33
Average gas price (per Mcf)	$ 2.91	$ 4.37
Average natural gas liquids (per Gal)	$ 0.98	$ 1.25
Oil equivalents (per BOE)	$ 96.63	$ 98.13

Lease Operating Expenses. Lease operating expenses, or LOE, not including production taxes increased to $24.3 million for the year ended December 31, 2012 from $20.9 million for 2011. This increase was mainly the result of an increase in expenses related to property taxes, chemicals and fuel, compressor rentals, contract pumpers, field supervision, equipment repairs and maintenance, salt water disposal and well workovers.

Production Taxes. Production taxes increased to $29.0 million for the year ended December 31, 2012 from $26.1 million for 2011. This increase was primarily related to a 10% increase in production partially offset by a 2% decrease in the average realized BOE price received, resulting in a 9% increase in oil and gas revenues.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization, or DD&A, expense increased to $90.7 million for the year ended December 31, 2012, and consisted of $90.2 million in depletion of oil and natural gas properties and $0.5 million in depreciation of other property and equipment, as compared to total DD&A expense of $62.3 million for 2011. This increase was due to an increase in our full cost pool as a result of our capital activities, an increase in our production and a decrease in our total proved reserves volume used to calculate our total DD&A expense.

General and Administrative Expenses. Net general and administrative expenses increased to $13.8 million for the year ended December 31, 2012 from $8.1 million for 2011. This $5.7 million increase was due to an increase in salaries, stock compensation expenses and benefits resulting from an increased number of employees, increases in legal expenses, franchise taxes and fees for auditing and tax services, partially offset by an increase in administrative services reimbursements under the acquisition team agreement and an increase in general and administrative costs related to exploration and development activity capitalized to the full cost pool.

Accretion Expense. Accretion expense remained relatively flat at $0.7 million for the years ended December 31, 2012 and 2011.

Interest Expense. Interest expense increased to $7.5 million for the year ended December 31, 2012 from $1.4 million for 2011 due to higher outstanding debt balances and higher weighted average interest rates. During 2011, total weighted debt outstanding under our revolving credit facility was approximately $21.1 million and bore a weighted average interest rate of 3.32%. During 2012, total weighted average debt outstanding under our revolving credit facility was approximately $45.0 million and bore a weighted average interest rate of 2.85%. On October 17, 2012, we issued $250.0 million aggregate principal amount of our 7.75% Senior Notes due 2020, a portion of the proceeds from which was used to repay all outstanding borrowings under our revolving credit facility. On December 21, 2012, we issued an additional $50.0 million aggregate principal amount of our 7.75% Senior Notes due 2020. In addition, we wrote off approximately $1.1 million of unamortized loan fees associated with our revolving credit facility in conjunction with the lowering of our borrowing base during the year ended December 31, 2012.

Income Taxes. As of December 31, 2012, we had a net operating loss carry forward of approximately $4.3 million, in addition to numerous temporary differences, which gave rise to a net deferred tax liability. Periodically, management performs a forecast of our taxable income to determine whether it is more likely than not that a valuation allowance is needed, looking at both positive and negative factors. A valuation allowance for our deferred tax assets is established if, in management's opinion, it is more likely than not that some portion will not be realized. At December 31, 2012, a valuation allowance of $4.6 million had been provided for state net operating loss and federal tax credit deferred tax assets based on the uncertainty these assets may be realized. We recognized an income tax expense from continuing and discontinued operations of $24.1 million for the year ended December 31, 2012.

Liquidity and Capital Resources

Overview. Historically, our primary sources of funds have been cash flow from our producing oil and natural gas properties, borrowings under our credit facility and the issuances of equity and debt securities. Our ability to access any of these sources of funds can be significantly impacted by decreases in oil and natural gas prices or oil and natural gas production. During 2012, we received aggregate net proceeds (before offering expenses) of approximately $427.9 million from the sale of shares of our common stock and approximately $290.3 million from the sale of our 7.75% Senior Notes due 2020. In January 2013, we received $32.8 million of net proceeds from the underwriters' exercise of their option to purchase the remaining shares of common stock subject to the over-allotment option granted in connection with our December 2012 equity offering. In 2013, we received an aggregate of $733.8 million from the sale of shares of our common stock. In addition, we received an aggregate of $192.7 million in net proceeds from the sale of shares of our Diamondback common stock in 2013.

Net cash flow provided by operating activities was $191.1 million for the year ended December 31, 2013 as compared to net cash flow provided by operating activities of $199.2 million for 2012. This decrease was primarily the result of a decrease in cash receipts from our oil and natural gas purchasers due to a 34% decrease in net realized BOE prices, partially offset by a 60% increase in our net BOE production.

Net cash flow provided by operating activities was $199.2 million for the year ended December 31, 2012, as compared to net cash flow provided by operating activities of $158.1 million for 2011. This increase was primarily the result of an increase in cash receipts from our oil and natural gas purchasers due to a 10% increase in our net BOE production, partially offset by a 2% decrease in net realized BOE prices.

Net cash used in investing activities for the year ended December 31, 2013 was $664.3 million as compared to $840.6 million for 2012. During the year ended December 31, 2013, we spent $808.2 million in additions to oil and natural gas properties, of which $335.2 million was spent on our 2013 drilling and recompletion programs, $93.4 million was spent on expenses attributable to the wells drilled and recompleted during 2012, $5.8 million was spent on compressors and other facility enhancements, $2.0 million was spent on plugging costs, $340.4 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and $5.2 million was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, $33.9 million was invested in Grizzly and $13.1 million was invested in our other equity investments during the year ended December 31, 2013. We also received $192.7 million from the sale of shares of our Diamondback common stock during 2013. During the year ended December 31, 2013, we used cash from operations and proceeds from our 2012 and 2013 equity and debt offerings for our investing activities.

Net cash used in investing activities for the year ended December 31, 2012 was $840.6 million as compared to $323.2 million for 2011. During the year ended December 31, 2012, we spent $757.2 million in additions to oil and natural gas properties, of which $175.4 million was spent on our 2012 drilling and recompletion programs, $38.8 million was spent on expenses attributable to the wells drilled and recompleted during 2011, $13.3 million was spent on compressors and other facility enhancements, $1.7 million was spent on plugging costs, $509.8 million was spent on lease related costs, primarily the acquisition of leases in the Utica Shale, and $5.0 million was spent on tubulars, with the remainder attributable mainly to capitalized general and administrative expenses. In addition, during the year ended December 31, 2012, $103.9 million was invested in Grizzly and an aggregate of $43.4 million was invested in our other equity investments. During the year ended December 31, 2012, we used cash from operations and proceeds from the Notes Offerings and the December 2012 Equity Offering for our investing activities.

Net cash provided by financing activities for the year ended December 31, 2013 was $765.1 million as compared to net cash provided by financing activities of $714.6 million for 2012. The 2013 amount provided by financing activities is primarily attributable to the net proceeds of $765.1 million from our 2013 equity offerings.

Net cash provided by financing activities for the year ended December 31, 2012 was $714.6 million as compared to $256.5 million for 2011. The 2012 amount provided by financing activities was primarily attributable to the net proceeds of $426.9 million from the December 2012 Equity Offering (not including the $32.8 received in January 2013 following the exercise by the underwriters of the December 2012 Equity Offering of their option to purchase an additional 900,000 shares of our common stock to cover over-allotments), $296.8 million from our offerings of 7.750% Senior Notes due 2020 and $0.2 million from the exercise of stock options.

Credit Facility. On September 30, 2010, we entered into a senior secured revolving credit facility with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association, or Amegy Bank. The revolving credit facility initially matured on September 30, 2013, had a maximum commitment amount of $100.0 million and had a borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. On May 3, 2011, we entered into a first amendment to the revolving credit facility with The Bank of Nova Scotia, Amegy Bank, KeyBank National Association, or KeyBank, and Société Générale. Under the terms of the first amendment, KeyBank and Société Générale were added as additional lenders, the maximum amount of the revolving credit facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by us under the credit facility were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, we entered into additional amendments to our revolving credit facility pursuant to which, among other things, the borrowing base under the facility was increased to $125.0 million. On December 14, 2011, we repaid all outstanding borrowings under the credit facility with a portion of the net proceeds of our equity offering completed on December 5, 2011 pending the application of such proceeds to fund certain Utica Shale lease acquisitions and for general corporate purposes. On May 2, 2012, we entered into an amendment to the revolving credit facility under which, among other things, the borrowing base was increased to $155.0 million. In addition, Credit Suisse, Deutsche Bank Trust Company Americas and IBERIABANK were added as additional lenders and Société Générale left the bank group.

On October 9, 2012, we entered into an amendment to our revolving credit facility that modified certain covenants to permit our October offering of 7.75% Senior Notes due 2020. The offering closed on October 17, 2012 and we repaid all indebtedness outstanding under our revolving credit facility on that date with a portion of the proceeds from the offering.

Effective as of October 17, 2012, we amended our revolving credit facility to lower the applicable rates (i) from a range of 1.00% to 1.75% to a range of 0.75% to 1.50% for the base rate loans and (ii) from a range of 2.00% to 2.75% to a range of 1.75% to 2.50% for the eurodollar rate loans and letters of credit. This amendment also lowered the commitment fees for Level 1 and Level 2 usage levels, in each case, from 0.50% per annum to 0.375% per annum. Also, effective as of October 17, 2012, in connection with the completion of our October offering and the contribution of our Permian Basin properties to Diamondback, our borrowing base under the credit facility was reduced to $45.0 million until the next borrowing base redetermination. Effective as of December 18, 2012, we entered into another amendment to our revolving credit facility that modified certain covenants to permit our December offering of 7.75% Senior Notes due 2020 and reduce the borrowing base under our revolving credit facility to $40.0 million until the next borrowing base redetermination.

In connection with the spring borrowing base redetermination of our revolving credit facility, completed as of June 6, 2013, we entered into an amendment to our revolving credit facility pursuant to which, among other things, our borrowing base under this facility was increased from $40.0 million to $50.0 million, an improved pricing grid was provided for and the maturity date of the facility was extended to June 2018. See also Note 7 to our financial statements included elsewhere in this report.

On December 27, 2013, we entered into an Amended and Restated Credit Agreement with The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders, which amends and restates in its entirety our existing credit agreement, dated as of September 30, 2010, as amended. The Amended and Restated Credit Agreement provides for an increase in the maximum facility amount from $350.0 million to $1.5 billion, with an increase in borrowing base availability as of December 27, 2013 from $50.0 million to $150.0 million. The Amended and Restated Credit Agreement matures on June 6, 2018.

Advances under our revolving credit facility, as amended, may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.5% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.5%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its “prime rate,” and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.5% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the “London Interbank Offered Rate” for deposits in U.S. dollars. We have had no outstanding borrowings under our revolving credit facility since October 17, 2012, on which date the outstanding borrowings, prior to repayment, bore interest at the eurodollar rate (2.97%) per annum.

As of December 31, 2013, there were no borrowings outstanding under our revolving credit facility. This facility is secured by substantially all of our assets. Our wholly-owned subsidiaries guarantee our obligations under our revolving credit facility.

Our revolving credit facility contains customary negative covenants including, but not limited to, restrictions on our and our subsidiaries' ability to: incur indebtedness; grant liens; pay dividends and make other restricted payments; make investments; make fundamental changes; enter into swap contracts and forward sales contracts; dispose of assets; change the nature of their business; and enter into transactions with their affiliates. The negative covenants are subject to certain exceptions as specified in our revolving credit facility. Our revolving credit facility also contains certain affirmative covenants, including, but not limited to the following financial covenants: (1) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and (2) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00. We were in compliance with these financial covenants at December 31, 2013.

Senior Notes. On October 17, 2012, we issued $250.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the October Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act under an indenture among us, our subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee.

On December 21, 2012, we issued an additional $50.0 million in aggregate principal amount of our 7.75% Senior Notes due 2020, or the December Notes, to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act. The December Notes were issued as additional securities under the existing senior note indenture. The December Notes and the October Notes are treated as a single class of debt securities under the senior note indenture and are referred to collectively herein as the "Notes". We used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under our revolving credit facility. We used the remaining net proceeds of the October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which includes funding a portion of our 2013 capital development plan.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are senior unsecured obligations and rank equally in the right of payment with all of our other senior indebtedness and senior in right of payment to any of our future subordinated indebtedness. All of our existing and future restricted subsidiaries that guarantee our secured revolving credit facility or certain other debt guarantee the Notes, provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of our future unrestricted subsidiaries. The guarantees rank equally in the right of payment with all of the senior indebtedness of the subsidiary guarantors and senior in the right of payment to any future subordinated indebtedness of the subsidiary guarantors. The Notes and the guarantees are effectively subordinated to all of our and the subsidiary guarantors' secured indebtedness (including all borrowings and other obligations under our revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries that do not guarantee the Notes.

We may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, we may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, we may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

If we experience a change of control (as defined in the senior note indenture), we will be required to make an offer to repurchase the Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase. If we sell certain assets and fail to use the proceeds in a manner specified in the senior note indenture, we will be required to use the remaining proceeds to make an offer to repurchase the Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of repurchase.

The senior note indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of our restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

Capital Expenditures. Our recent capital commitments have been primarily for the execution of our drilling programs, for acquisitions (primarily in the Utica Shale), to fund Grizzly's delineation drilling program and initial preparation of the Algar Lake facility and for investments in entities that may provide services to facilitate the development of our acreage. Our strategy is to continue to (1) increase cash flow generated from our operations by undertaking new drilling, workover, sidetrack and recompletion projects to exploit our existing properties, subject to economic and industry conditions, (2) pursue acquisition and disposition opportunities and (3) pursue business integration opportunities.

Of our net reserves at December 31, 2013, 35.2% were categorized as proved undeveloped. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved developed reserves, or both. To realize reserves and increase production, we must continue our exploratory drilling, undertake other replacement activities or use third parties to accomplish those activities.

During 2013, we spud 52 gross (39 net) wells in the Utica Shale for a total cost of approximately $301.9 million. We currently expect our 2014 capital expenditures to be $594.0 million to $634.0 million to drill 85 to 95 gross (64 to 71 net) wells on our Utica Shale acreage. In addition, we currently expect to spend $225.0 million to $275.0 million in 2014 to acquire additional acreage in the Utica Shale.

During 2013, we recompleted 87 existing wells and spud 22 new wells for a total cost of approximately $70.0 million at our WCBB field. We currently intend to drill 22 to 24 new wells during 2014 at our WCBB field for aggregate estimated drilling and recompletion expenditures during 2014 of $42.0 million to $45.0 million.

In our Hackberry fields, in 2013, we recompleted 63 existing wells and spud 18 new wells for a total cost of approximately $62.6 million. We currently intend to drill ten to twelve wells in our Hackberry fields in 2014. Total capital expenditures for our Hackberry fields during 2014 are estimated to be approximately $24.0 million to $26.0 million.

During 2013, no new wells were spud on our Niobrara Formation acreage. We do not currently anticipate any capital expenditures in the Niobrara Formation in 2014.

During the third quarter of 2006, we purchased a 24.9% interest in Grizzly. As of December 31, 2013, our net investment in Grizzly was approximately $191.5 million. Our capital requirements in 2013 for Grizzly were approximately $33.9 million, primarily for the expenses associated with the construction of the Algar Lake facility and drilling activity during the 2013-2014 winter drilling season. Effective October 5, 2012, Grizzly entered into a $125.0 million revolving credit facility, of which $75.0 million has been borrowed to fund additional infrastructure relating to the Algar Lake facility and other future development projects. Our capital requirements in 2014 related to Grizzly's activities are currently estimated to be approximately $15.0 million to $20.0 million.

We had capital expenditures of approximately $1.8 million during the year ended December 31, 2013 related to our interests in Thailand. We do not currently anticipate any capital expenditures in Thailand in 2014.

In an effort to facilitate the development of our Utica Shale and other domestic acreage, we have invested in entities that can provide services that are required to support our operations. In the first quarter of 2013, we participated in the formation of Stingray Energy with an initial ownership interest of 50%. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites. In 2012, we participated in the formation of Stingray Pressure, Stingray Cementing and Stingray Logistics, with an initial ownership interest in each entity of 50%. These entities provide well completion and other well services. In 2012, we also participated in the formation of Blackhawk and Timber Wolf, with an initial ownership interest of 50% in each entity. Blackhawk coordinates gathering, compression, processing and marketing activities in connection with the development of our Utica Shale acreage and Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. Also in 2012, we acquired a 22.5% equity interest in Midstream which owns a 28.4% equity interest in a gas processing plant in West Texas. In 2011 and 2012, we acquired an aggregate 40% equity interest in Bison, which owns and operates drilling rigs and related equipment. Also in 2011, we acquired a 25% interest in Muskie, which is engaged in the processing and sale of hydraulic fracturing grade sand. See Note 5 to our consolidated financial statements included elsewhere in this report for additional information regarding these other investments. In the year ended December 31, 2013, we invested approximately $10.0 million in these entities. In 2014, we expect to invest approximately $15.0 million to $20.0 million in these entities. We are currently evaluating strategic alternatives with respect to these oil field service entities. A registration statement on Form S-1 has been submitted to the SEC on a confidential basis in connection with certain of these interests, and we may choose to pursue an initial public offering of these interest later this year subject to market conditions. In January 2014, Blackhawk completed the sale of its equity interests in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which we received $84.8 million in net proceeds.

Our total capital expenditures for 2014 are currently estimated to be in the range of $675.0 million to $725.0 million. In addition, we currently expect to spend $225.0 million to $275.0 million in 2014 to acquire additional Utica Shale acreage, which includes the $185.0 million acquisition discussed in Item 1. "Business - Recent Developments". Approximately 88% of our 2014 estimated capital expenditures are currently expected to be spent in the Utica Shale. This range is up from the $513.5 million spent on 2013 activities, excluding Utica leasehold acquisitions, primarily due to the significant increase in our acreage position in the Utica Shale and our contemplated Utica development plans. We intend to continue to monitor pricing and cost developments and make adjustments to our future capital expenditure programs as warranted.

We believe that our cash on hand, cash flow from operations, proceeds from our recent offerings of debt and equity securities, the sale of our Diamondback common stock, distributions from Blackhawk and borrowings under our revolving credit facility will be sufficient to meet our normal recurring operating needs and capital requirements for the next twelve months. In the event we elect to further expand or accelerate our drilling program or pursue additional acquisitions, or Grizzly's oil sands projects are accelerated, we may be required to obtain additional funds which we would seek to do through traditional borrowings, offerings of debt or equity securities or other means, including the sale of assets. We regularly evaluate new acquisition opportunities. Needed capital may not be available to us on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to delay or curtail implementation of our business plan or not be able to complete acquisitions that may be favorable to us.

Commodity Price Risk

The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past six years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel in December 2008 to a high of $145.31 per barrel in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per million British thermal units, or MMBtu, in September 2009 to a high of $13.31 per MMBtu in July 2008. On February 21, 2014, the West Texas Intermediate posted price for crude oil was $102.20 per barrel and the Henry Hub spot market price of natural gas was $6.14 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations on our oil and natural gas production, we had the following open fixed price swaps and swaptions at December 31, 2013:

	Volume (barrels per day)	Weighted Average Price ($ per Bbl)
Fixed Price Swaps:		
January 2014 - March 2014	4,000	$ 104.75
April 2014 - December 2014	2,000	$ 101.50

	Volume (MMBtu per day)	Weighted Average Price ($ per MMBtu)
Fixed Price Swaps and Swaptions:		
January 2014	65,000	$ 4.04
February 2014 - December 2014	105,000	$ 4.01
January 2015 - December 2015	125,000	$ 4.03
January 2016 - March 2016	105,000	$ 4.04
April 2016	95,000	$ 4.04

Under the 2012 contracts, we hedged approximately 46% of our 2012 production. Under the 2013 fixed price swap contracts, we hedged approximately 48% of our 2013 production. Under the 2014 contracts, we have hedged approximately 41% to 49% of our expected 2014 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements.

Commitments

In connection with our acquisition in 1997 of the remaining 50% interest in the WCBB properties, we assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004, to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, we can access the trust for use in plugging and abandonment charges associated with the property. As of December 31, 2013, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2013, we have plugged 354 wells at WCBB since we began our plugging program in 1997, which management believes fulfills our current minimum plugging obligation.

Contractual and Commercial Obligations

The following table sets forth our contractual and commercial obligations at December 31, 2013:

	Payment due by period (1)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
7.75% senior unsecured notes due 2020	$ 461,846	$ 23,250	$ 46,500	$ 46,500	$ 345,596
Asset retirement obligations	15,083	795	1,383	793	12,112
Employment agreements	3,467	1,800	1,667	—	—
Building loan (2)	1,995	159	1,836	—	—
Firm transportation contracts	1,101,260	40,783	133,898	138,033	788,546
Operating leases	1,854	536	920	398	—
Total	$ 1,585,505	$ 67,323	$ 186,204	$ 185,724	$ 1,146,254

(1) Does not include short-term derivative instruments of $12.0 million, which are due in less than one year.
(2) Does not include estimated interest of $112,000 due in less than one year and $118,000 due in 1-3 years.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2013.

New Accounting Pronouncements

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-02*, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income,"* which requires additional information about amounts reclassified out of accumulated other comprehensive income by component. This ASU requires the presentation, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, a cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The requirements of this ASU are effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. We have adopted the provisions of this ASU for reporting periods in 2013. Adoption of this ASU had no impact on our financial position or results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors, including: worldwide and domestic supplies of oil and natural gas; the level of prices, and expectations about future prices, of oil and natural gas; the cost of exploring for, developing, producing and delivering oil and natural gas; the expected rates of declining current production; weather conditions, including hurricanes, that can affect oil and natural gas operations over a wide area; the level of consumer demand; the price and availability of alternative fuels; technical advances affecting energy consumption; risks associated with operating drilling rigs; the availability of pipeline capacity; the price and level of foreign imports; domestic and foreign governmental regulations and taxes; the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; political instability or armed conflict in oil and natural gas producing regions; and the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the West Texas Intermediate posted price for crude oil has ranged from a low of $30.28 per barrel, or Bbl, in December 2008 to a high of $145.31 per Bbl in July 2008. The Henry Hub spot market price of natural gas has ranged from a low of $1.83 per MMBtu in September 2009 to a high of $13.31 per MMBtu in July 2008. On February 21, 2014, the West Texas Intermediate posted price for crude oil was $102.20 per barrel and the Henry Hub spot market price of natural gas was $6.14 per MMBtu. Any substantial decline in the price of oil and natural gas will likely have a material adverse effect on our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves, and may result in write downs of oil and natural gas properties due to ceiling test limitations.

To mitigate the effects of commodity price fluctuations on our oil and natural gas production, we had the following open fixed price swaps and swaptions at December 31, 2013:

	Volume (barrels per day)	Weighted Average Price ($ per Bbl)
Fixed Price Swaps:		
January 2014 - March 2014	4,000	$ 104.75
April 2014 - December 2014	2,000	$ 101.50

	Volume (MMBtu per day)	Weighted Average Price ($ per MMBtu)
Fixed Price Swaps and Swaptions:		
January 2014	65,000	$ 4.04
February 2-14 - December 2014	105,000	$ 4.01
January 2015 - December 2015	125,000	$ 4.03
January 2016 - March 2016	105,000	$ 4.04
April 2016	95,000	$ 4.04

In January 2014, we entered into fixed price swaps for 25,000 MMBtu of natural gas per day at a weighted average price of $4.20 per MMBtu for the period from May 2014 through December 2015. For the period from June 2014 through December 2015, we entered into fixed price swaps for 25,000 MMBtu of natural gas per day at a weighted average price of $4.21 per MMBtu. Our fixed price swap contracts are tied to the commodity prices on NYMEX. We will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas.

Under our 2014 contracts, we have hedged approximately 41% to 49% of our estimated 2014 production. Such arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. These fixed price swaps are accounted for as cash flow hedges and recorded at fair value pursuant to FASB ASC 815 and related pronouncements. At December 31, 2013, we had a net liability derivative position of $22.8 million as compared to a net liability derivative position of $9.5 million as of December 31, 2012, related to our fixed price swaps. Utilizing actual derivative contractual volumes, a 10% increase in underlying commodity prices would have reduced the fair value of these instruments by approximately $44.4 million, while a 10% decrease in underlying commodity prices would have increased the fair value of these instruments by approximately $44.4 million. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Our revolving credit facility is structured under floating rate terms, as advances under this facility may be in the form of either base rate loans or eurodollar loans. As such, our interest expense is sensitive to fluctuations in the prime rates in the U.S. or, if the eurodollar rates are elected, the eurodollar rates. As of December 31, 2013, we had no variable interest rate borrowings outstanding; therefore, an increase in interest rates would not have impacted our interest expense. As of December 31, 2013, we did not have any interest rate swaps to hedge our interest risks.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 following the signature pages of this Report.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of our Interim Chief Executive Officer, President and Chief Financial Officer, we have established disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Interim Chief Executive Officer, President and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

As of December 31, 2013, an evaluation was performed under the supervision and with the participation of management, including our Interim Chief Executive Officer, President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Interim Chief Executive Officer, President and Chief Financial Officer has concluded that, as of December 31, 2013, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during our last fiscal quarter that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for the fair presentation of the consolidated financial statements of Gulfport Energy Corporation. Management is also responsible for establishing and maintaining a system of adequate internal controls over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 1992 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 1992 *Internal Control-Integrated Framework*, management did not identify any material weaknesses in our internal control over financial reporting and concluded that our internal control over financial reporting was effective as of December 31, 2013.

Grant Thornton LLP, the independent registered public accounting firm that audited our financial statements for the year ended December 31, 2013 included with this Annual Report on Form 10-K, has also audited our internal control over financial reporting as of December 31, 2013, as stated in their accompanying report.

/s/ Michael G. Moore

Name:	Michael G. Moore
Title:	Interim Chief Executive Officer, President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the internal control over financial reporting of Gulfport Energy Corporation and Subsidiaries (the "Company") as of December 31, 2013, based on criteria established in the 1992 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). 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 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2013 and our report dated February 28, 2014 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 28, 2014

ITEM 9B. OTHER INFORMATION

On February 14, 2014, as previously announced, James D. Palm resigned as our Chief Executive Officer and from our Board of Directors. Michael G. Moore, our President and Chief Financial Officer, assumed the additional title and responsibilities of our Interim Chief Executive Officer upon Mr. Palm's resignation, pending the completion of our search process for and appointment of a new chief executive officer. On February 24, 2014, the Compensation Committee of our Board of Directors granted Mr. Moore a retention award of 24,868 shares of our common stock (the "Restricted Shares") pursuant to a restricted stock award certificate (the "Award Certificate") under our 2013 Restated Stock Incentive Plan. The Restricted Shares vest in two equal installments on the first and second anniversary of the grant date, subject to Mr. Moore's continuous service with us. Vesting of the Restricted Shares will accelerate upon the earlier of Mr. Moore's involuntary termination without cause, termination for good reason, death, disability or termination for any reason except cause or voluntary termination without good reason within 24 months after a change in control, as described in the form of award certificate, a copy of which is filed as an exhibit to this Annual Report on Form 10-K.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10-Directors, Executive Officers and Corporate Governance, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 11. EXECUTIVE COMPENSATION

For information concerning Item 11-Executive Compensation, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

For information concerning Item 12-Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission within 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

For information concerning Item 13-Certain Relationships and Related Transactions, and Director Independence, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

For information concerning Item 14-Principal Accounting Fees and Services, see our definitive proxy statement, which will be filed with the Securities and Exchange Commission with 120 days after the close of our previous fiscal year and is incorporated herein by this reference (with the exception of portions noted therein that are not incorporated by reference).

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as part of this report or incorporated by reference herein:

(1) *Financial Statements*
Reference is made to the Index to Financial Statements appearing on Page F-1.

Reference is also made to the Financial Statements of Diamondback Energy, Inc. ("Diamondback") that have been included on pages F-1 to F-39 in Diamondback's Annual Report on Form 10-K (File No. 001-35700) filed with the SEC on February 19, 2014, which Financial Statements are incorporated herein by reference.

(2) *Financial Statement Schedules*
All financial statement schedules have been omitted because they are not applicable or the required disclosure is presented in the financial statements or notes thereto.

(3) *Exhibits*

Exhibit Number	Description
2.1	Contribution Agreement, dated May 7, 2012, by and between the Company and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 8, 2012).
2.2	Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 18, 2012).
2.3	Amendment, dated December 19, 2012, to the Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 20, 2012).
2.4	Purchase and Sale Agreement, dated February 11, 2013, by and between Windsor Ohio, LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 15, 2013).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).

4.3	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.4	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
4.5	Indenture, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Gulfport Energy Corporation's 7.750% Senior Note Due November 1, 2020) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.6	Registration Rights Agreement, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.7	First Supplemental Indenture, dated December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
4.8	Registration Rights Agreement, dated as of December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
10.1+	2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.3+*	Form of Restricted Stock Award Agreement.
10.4+	Consulting Agreement, effective as of June 14, 2013, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 19, 2013).
10.5+	Separation and Release Agreement, dated as of January 31, 2014, by and between the Company and James D. Palm (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 4, 2014).
10.6+	Employment Agreement, dated November 7, 2012, between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.6 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 8, 2012).
10.7	Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
10.8	Investor Rights Agreement, dated as of October 11, 2012, between Gulfport Energy Corporation and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 17, 2012).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company.

23.4*	Consent of Grant Thornton LLP with respect to financial statements of Diamondback Energy, Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Ryder Scott Company.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** Furnished herewith, not filed.

\+ Management contract, compensatory plan or arrangement.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 28, 2014

GULFPORT ENERGY CORPORATION

By: /s/ MICHAEL G. MOORE

Michael G. Moore
Interim Chief Executive Officer

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date:	February 28, 2014	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **Interim Chief Executive Officer** **(Principal Executive Officer)**
Date:	February 28, 2014	By:	/s/ DAVID L. HOUSTON **David L. Houston** **Chairman of the Board and Director**
Date:	February 28, 2014	By:	/s/ MICHAEL G. MOORE **Michael G. Moore** **President and Chief Financial Officer** **(Principal Financial and Accounting Officer)**
Date:	February 28, 2014	By:	/s/ DONALD DILLINGHAM **Donald Dillingham** **Director**
Date:	February 28, 2014	By:	/s/ CRAIG GROESCHEL **Craig Groeschel** **Director**
Date:	February 28, 2014	By:	/s/ SCOTT E. STRELLER **Scott E. Streller** **Director**

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Gulfport Energy Corporation:

We have audited the accompanying consolidated balance sheets of Gulfport Energy Corporation and Subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Gulfport Energy Corporation and Subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We also have 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, 2013, based on criteria established in the 1992 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 28, 2014

GULFPORT ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(In thousands, except share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 458,956	$ 167,088
Accounts receivable—oil and gas	58,824	25,615
Accounts receivable—related parties	2,617	34,848
Prepaid expenses and other current assets	2,581	1,506
Deferred tax asset	6,927	—
Short-term derivative instruments	324	664
Note receivable - related party	875	—
Total current assets	531,104	229,721
Property and equipment:		
Oil and natural gas properties, full-cost accounting, $950,590 and $626,295 excluded from amortization in 2013 and 2012, respectively	2,477,178	1,611,090
Other property and equipment	11,131	8,662
Accumulated depletion, depreciation, amortization and impairment	(784,717)	(665,884)
Property and equipment, net	1,703,592	953,868
Other assets:		
Equity investments ($178,708 and $151,317 attributable to fair value option in 2013 and 2012, respectively)	440,068	381,484
Derivative instruments	521	—
Other assets	17,851	13,295
Total other assets	458,440	394,779
Total assets	$ 2,693,136	$ 1,578,368
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 190,707	$ 110,244
Asset retirement obligation—current	795	60
Short-term derivative instruments	12,280	10,442
Current maturities of long-term debt	159	150
Total current liabilities	203,941	120,896
Long-term derivative instrument	11,366	—
Asset retirement obligation—long-term	14,288	13,215
Deferred tax liability	114,275	18,607
Long-term debt, net of current maturities	299,028	298,888
Other non-current liabilities	—	354
Total liabilities	642,898	451,960
Commitments and contingencies (Notes 16 and 17)		
Preferred stock, $.01 par value; 5,000,000 authorized, 30,000 authorized as redeemable 12% cumulative preferred stock, Series A; 0 issued and outstanding	—	—
Stockholders' equity:		
Common stock - $.01 par value, 200,000,000 authorized, 85,177,532 issued and outstanding in 2013 and 67,527,386 in 2012	851	674
Paid-in capital	1,813,058	1,036,245
Accumulated other comprehensive loss	(9,781)	(3,429)
Retained earnings	246,110	92,918
Total stockholders' equity	2,050,238	1,126,408
Total liabilities and stockholders' equity	$ 2,693,136	$ 1,578,368

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31,		
	2013	2012	2011
	(In thousands, except share data)		
Revenues:			
Oil and condensate sales	$ 224,129	$ 242,708	$ 222,025
Gas sales	21,015	3,225	3,838
Natural gas liquid sales	17,081	2,668	3,090
Other income	528	325	301
	262,753	248,926	229,254
Costs and expenses:			
Lease operating expenses	26,703	24,308	20,897
Production taxes	26,933	28,957	26,054
Midstream transportation, processing and marketing	11,030	443	279
Depreciation, depletion and amortization	118,880	90,749	62,320
General and administrative	22,519	13,808	8,074
Accretion expense	717	698	666
(Gain) loss on sale of assets	508	(7,300)	—
	207,290	151,663	118,290
INCOME FROM OPERATIONS	55,463	97,263	110,964
OTHER (INCOME) EXPENSE:			
Interest expense	17,490	7,458	1,400
Interest income	(297)	(72)	(186)
(Income) loss from equity method investments	(213,058)	(8,322)	1,418
	(195,865)	(936)	2,632
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	251,328	98,199	108,332
INCOME TAX EXPENSE (BENEFIT)	98,136	26,363	(90)
INCOME FROM CONTINUING OPERATIONS	153,192	71,836	108,422
DISCONTINUED OPERATIONS			
Loss on disposal of Belize properties, net of tax	—	3,465	—
NET INCOME	$ 153,192	$ 68,371	$ 108,422
NET INCOME PER COMMON SHARE:			
Basic net income from continuing operations per share	$ 1.98	$ 1.28	$ 2.22
Basic net income from discontinued operations, net of tax, per share	$ —	(0.06)	—
Basic net income per share	$ 1.98	$ 1.22	$ 2.22
Diluted net income from continuing operations per share	$ 1.97	$ 1.27	$ 2.20
Diluted net income from discontinued operations, net of tax, per share	—	(0.06)	—
Diluted net income per share	$ 1.97	$ 1.21	$ 2.20
Weighted average common shares outstanding—Basic	77,375,683	55,933,354	48,754,840
Weighted average common shares outstanding—Diluted	77,861,646	56,417,488	49,206,963

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Net income	$ 153,192	$ 68,371	$ 108,422
Foreign currency translation adjustment	(12,223)	1,355	(1,865)
Change in fair value of derivative instruments (1)	(4,419)	(8,452)	1,576
Reclassification of settled contracts (2)	10,290	1,005	4,720
Other comprehensive income (loss)	(6,352)	(6,092)	4,431
Comprehensive income	$ 146,840	$ 62,279	$ 112,853

(1) Net of $4.3 million and $(4.3) million in taxes for the years ended December 31, 2013 and 2012, respectively. No taxes were recorded in the year ended 2011.

(2) Net of $(0.5) million and $0.5 million in taxes for the years ended December 31, 2013 and 2012, respectively. No taxes were recorded in the year ended 2011.

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity
	Shares	Amount				
			(In thousands, except share data)			
Balance at January 1, 2011	44,645,435	$ 446	$ 296,253	$ (1,768)	$ (83,875)	$ 211,056
Net income	—	—	—	—	108,422	108,422
Other Comprehensive Income	—	—	—	4,431	—	4,431
Stock Compensation	—	—	1,287	—	—	1,287
Issuance of Common Stock in public offerings, net of related expenses	10,810,000	108	306,053	—	—	306,161
Issuance of Common Stock through exercise of warrants	566	—	—	—	—	—
Issuance of Restricted Stock	63,370	1	(1)	—	—	—
Issuance of Common Stock through exercise of options	102,000	1	992	—	—	993
Balance at December 31, 2011	55,621,371	556	604,584	2,663	24,547	632,350
Net income	—	—	—	—	68,371	68,371
Other Comprehensive Loss	—	—	—	(6,092)	—	(6,092)
Stock Compensation	—	—	4,688	—	—	4,688
Issuance of Common Stock in public offerings, net of related expenses	11,750,000	118	426,789	—	—	426,907
Issuance of Restricted Stock	135,015	—	—	—	—	—
Issuance of Common Stock through exercise of options	21,000	—	184	—	—	184
Balance at December 31, 2012	67,527,386	674	1,036,245	(3,429)	92,918	1,126,408
Net income	—	—	—	—	153,192	153,192
Other Comprehensive Loss	—	—	—	(6,352)	—	(6,352)
Stock Compensation	—	—	10,495	—	—	10,495
Issuance of Common Stock in public offerings, net of related expenses	17,287,500	173	764,922	—	—	765,095
Issuance of Restricted Stock	237,646	3	(3)	—	—	—
Issuance of Common Stock through exercise of options	125,000	1	1,399			1,400
Balance at December 31, 2013	85,177,532	$ 851	$ 1,813,058	$ (9,781)	$ 246,110	$ 2,050,238

See accompanying notes to consolidated financial statements.

GULFPORT ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 153,192	$ 68,371	$ 108,422
Adjustments to reconcile net income to net cash provided by operating activities:			
Accretion of discount—Asset Retirement Obligation	717	698	666
Depletion, depreciation and amortization	118,880	90,749	62,320
Stock-based compensation expense	6,297	2,813	772
(Gain) loss from equity investments	(212,714)	(8,322)	1,418
Interest income - note receivable	(26)	(2)	(147)
Unrealized loss (gain) on derivative instruments	18,189	144	(25)
Deferred income tax expense (benefit)	84,951	24,120	(372)
Amortization of loan commitment fees	1,012	640	540
Amortization of note discount and premium	298	59	—
Write off of loan commitment fees	—	1,143	—
Loss on disposal of assets	—	5,702	—
Gain on sale of assets	—	(7,300)	—
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(33,209)	2,404	(13,067)
Decrease (increase) in accounts receivable—related party	32,231	(30,117)	(4,158)
(Increase) decrease in prepaid expenses	(1,075)	(179)	405
Increase in other assets	(4,523)	—	—
Increase in accounts payable and accrued liabilities	29,310	50,506	1,612
Settlement of asset retirement obligation	(2,465)	(2,271)	(248)
Net cash provided by operating activities	191,065	199,158	158,138
Cash flows from investing activities:			
Deductions to cash held in escrow	8	8	8
Additions to other property and equipment	(2,322)	(638)	(415)
Additions to oil and gas properties	(808,183)	(757,192)	(287,292)
Proceeds from sale of other property and equipment	113	140	—
Proceeds from sale of oil and gas properties	—	63,590	1,384
Advances on note receivable to related party	(875)	—	(3,182)
Proceeds from sale of investments	192,737	—	—
Contributions to equity method investments	(47,014)	(147,307)	(34,621)
Distributions from equity method investments	1,276	820	870
Net cash used in investing activities	(664,260)	(840,579)	(323,248)
Cash flows from financing activities:			
Principal payments on borrowings	(149)	(158,639)	(97,634)
Borrowings on line of credit	—	158,500	48,000
Proceeds from bond issuance	—	296,835	—
Debt issuance costs and loan commitment fees	(1,283)	(9,175)	(981)
Proceeds from issuance of common stock, net of offering costs	766,495	427,091	307,154
Net cash provided by financing activities	765,063	714,612	256,539
Net increase in cash and cash equivalents	291,868	73,191	91,429
Cash and cash equivalents at beginning of period	167,088	93,897	2,468
Cash and cash equivalents at end of period	$ 458,956	$ 167,088	$ 93,897
Supplemental disclosure of cash flow information:			
Interest payments	$ 24,280	$ 1,461	$ 991
Income tax payments	$ 2,761	$ 261	$ 1
Supplemental disclosure of non-cash transactions:			
Capitalized stock based compensation	$ 4,198	$ 1,875	$ 515
Asset retirement obligation capitalized	$ 3,556	$ 2,195	$ 1,390
Interest capitalized	$ 7,132	$ —	$ —
Foreign currency translation (loss) gain on investment in Grizzly Oil Sands ULC	$ (12,223)	$ 1,355	$ (855)
Foreign currency translation (loss) gain on note receivable - related party	$ —	$ —	$ (1,085)

See accompanying notes to consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Business

Gulfport Energy Corporation ("Gulfport" or the "Company") is an independent oil and gas exploration, development and production company with its principal properties located in the Utica Shale in Eastern Ohio, along the Louisiana Gulf Coast and in Western Colorado in the Niobrara Formation, and has investments in companies operating in the Permian Basin in West Texas, Canada and Thailand.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents for purposes of the statement of cash flows.

Principles of Consolidation

The consolidated financial statements include the Company and its wholly owned subsidiaries, Grizzly Holdings Inc., Jaguar Resources LLC, Gator Marine, Inc., Gator Marine Ivanhoe, Inc., Westhawk Minerals LLC and Puma Resources, Inc. All intercompany balances and transactions are eliminated in consolidation.

Accounts Receivable

The Company's accounts receivable—oil and gas primarily are from companies in the oil and gas industry. The majority of its receivables are from one purchaser of the Company's oil and gas and receivables from joint interest owners on properties the Company operates. Credit is extended based on evaluation of a customer's payment history and, generally, collateral is not required. Accounts receivable are due within 30 days and are stated at amounts due from customers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the customer's current ability to pay its obligation to the Company, amounts which may be obtained by an offset against production proceeds due the customer and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2013 and December 31, 2012.

Oil and Gas Properties

The Company uses the full cost method of accounting for oil and gas operations. Accordingly, all costs, including nonproductive costs and certain general and administrative costs directly associated with acquisition, exploration and development of oil and gas properties, are capitalized. Under the full cost method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the 12-month unweighted average of the first-day-of-the-month price for 2013, 2012 and 2011, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or noncash writedown is required.

Such capitalized costs, including the estimated future development costs and site remediation costs of proved undeveloped properties are depleted by an equivalent units-of-production method, converting gas to barrels at the ratio of six Mcf of gas to one barrel of oil. No gain or loss is recognized upon the disposal of oil and gas properties, unless such dispositions significantly alter the relationship between capitalized costs and proven oil and gas reserves. Oil and gas properties not subject to amortization consist of the cost of unproved leaseholds and totaled $950.6 million and $626.3 million at December 31, 2013 and December 31, 2012, respectively. These costs are reviewed quarterly by management for impairment.

If impairment has occurred, the portion of cost in excess of the current value is transferred to the cost of oil and gas properties subject to amortization. Factors considered by management in its impairment assessment include drilling results by Gulfport and other operators, the terms of oil and gas leases not held by production, and available funds for exploration and development.

The Company accounts for its abandonment and restoration liabilities under FASB ASC Topic 410, "*Asset Retirement and Environmental Obligations*" ("FASB ASC 410"), which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed into service. When the liability is initially recorded, the Company increases the carrying amount of oil and natural gas properties by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is included in capitalized costs and depreciated consistent with depletion of reserves. Upon settlement of the liability or the sale of the well, the liability is reversed. These liability amounts may change because of changes in asset lives, estimated costs of abandonment or legal or statutory remediation requirements.

Other Property and Equipment

Depreciation of other property and equipment is provided on a straight-line basis over the estimated useful lives of the related assets, which range from 3 to 30 years.

Foreign Currency

The U.S. dollar is the functional currency for Gulfport's consolidated operations. However, the Company has an equity investment in a Canadian entity whose functional currency is the Canadian dollar. The assets and liabilities of the Canadian investment are translated into U.S. dollars based on the current exchange rate in effect at the balance sheet dates. Canadian income and expenses are translated at average rates for the periods presented and equity contributions are translated at the current exchange rate in effect at the date of the contribution. Translation adjustments have no effect on net income and are included in accumulated other comprehensive income in stockholders' equity. The following table presents the balances of the Company's cumulative translation adjustments included in accumulated other comprehensive income (loss).

		(In thousands)
December 31, 2010	$	2,952
December 31, 2011	$	1,087
December 31, 2012	$	2,442
December 31, 2013	$	(9,781)

Net Income per Common Share

Basic net income per common share is computed by dividing income attributable to common stock by the weighted average number of common shares outstanding for the period. Diluted net income per common share reflects the potential dilution that could occur if options or other contracts to issue common stock were exercised or converted into common stock. Potential common shares are not included if their effect would be anti-dilutive. Calculations of basic and diluted net income per common share are illustrated in Note 12.

Income Taxes

Gulfport uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income during the period the rate change is enacted. Deferred tax assets are recognized as income in the year in which realization becomes determinable. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company is subject to U.S. federal income tax as well as income tax of multiple jurisdictions. The Company's 1999 – 2013 U.S. federal and state income tax returns remain open to examination by tax authorities, due to net operating losses. As of December 31, 2013, the Company has no unrecognized tax benefits that would have a material impact on the effective rate.

The Company recognizes interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. For the year ended December 31, 2013, there is no interest or penalties associated with uncertain tax positions in the Company's consolidated financial statements.

Revenue Recognition

Natural gas revenues are recorded in the month produced and delivered to the purchaser using the entitlement method, whereby any production volumes received in excess of the Company's ownership percentage in the property are recorded as a liability. If less than Gulfport's entitlement is received, the underproduction is recorded as a receivable. At December 31, 2013, the Company had no gas imbalance liability. At December 31, 2012, the Company had a gas imbalance liability of approximately $0.4 million. Oil revenues are recognized when ownership transfers, which occurs in the month produced.

Investments—Equity Method

Investments in entities in which the Company owns an equity interest greater than 20% and less than 50% and/or investments in which it has significant influence are accounted for under the equity method. Under the equity method, the Company's share of investees' earnings or loss is recognized in the statement of operations. In accordance with FASB ASC 825, *"Financial Instruments*," the Company has elected the fair value option of accounting for its equity method investment in the common stock of Diamondback Energy Inc. ("Diamondback"). At the end of each reporting period, the quoted closing market price of Diamondback's common stock is multiplied by the total shares owned by the Company and the resulting gain or loss is recognized in (income) loss from equity method investments in the consolidated statements of operations.

The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company recognizes an impairment provision. There was no impairment of equity method investments at December 31, 2013 or 2012.

Accounting for Stock-Based Compensation

The Company accounts for stock-based compensation in accordance with the provisions of FASB ASC Topic 718, "*Compensation—Stock Compensation*" ("FASB ASC 718"). FASB ASC 718 requires share-based payments to employees, including grants of employee stock options and restricted stock, to be recognized as equity or liabilities at the fair value on the date of grant and to be expensed over the applicable vesting period. The vesting periods for the options range between three to five years and have a maximum contractual term of ten years. The vesting periods for restricted shares range between three to five years with either quarterly or annual vesting installments.

Accounting for Derivative Instruments and Hedging Activities

The Company may seek to reduce its exposure to unfavorable changes in oil and natural gas prices by utilizing energy swaps and collars, or fixed-price contracts. The Company follows the provisions of FASB ASC 815, "*Derivatives and Hedging*" ("FASB ASC 815") as amended. It requires that all derivative instruments be recognized as assets or liabilities in the balance sheet, measured at fair value.

The Company estimates the fair value of all derivative instruments using established index prices and other sources. These values are based upon, among other things, futures prices, correlation between index prices and the Company's realized prices, time to maturity and credit risk. The values reported in the consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation. Designation is established at the inception of a derivative, but re-designation is permitted. For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and revenues and expenses during the reporting period. Actual results could differ materially from those estimates. Significant estimates with regard to these financial statements include the estimate of proved oil and gas reserve quantities and the related present value of estimated future net cash flows there from, the amount and timing of asset retirement obligations, the realization of deferred tax assets and the realization of future net operating loss carryforwards available as reductions of income tax expense. The estimate of the Company's oil and gas reserves is used to compute depletion, depreciation, amortization and impairment of oil and gas properties.

Reclassification

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

Recent Accounting Pronouncements

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-02, *"Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income,"* which requires additional information about amounts reclassified out of accumulated other comprehensive income by component. This ASU requires the presentation, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, a cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The requirements of this ASU are effective prospectively for reporting periods beginning after December 15, 2012 with early adoption permitted. Adoption of the provisions of this ASU did not have a material effect on the Company's consolidated financial statements.

In May 2011, the FASB issued ASU No. 2011-04, *"Fair Value Measurement: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,"* which provides amendments to FASB ASC Topic 820, *"Fair Value Measurements and Disclosure"* ("FASB ASC 820"). The purpose of the amendments in this update is to create common fair value measurement and disclosure requirements between GAAP and IFRS. The amendments change certain fair value measurement principles and enhance the disclosure requirements. The amendments to FASB ASC 820 were effective for interim and annual periods beginning after December 15, 2011. Adoption of this ASU for reporting periods in 2012 had no impact on the Company's financial position or results of operations.

In June 2011, the FASB issued ASU 2011-05, *"Comprehensive Income: Presentation of Comprehensive Income,"* which provides amendments to FASB ASC Topic 220, *"Comprehensive Income"* ("FASB ASC 220"). The purpose of the amendments in this update is to provide a more consistent method of presenting non-owner transactions that affect an entity's equity. The amendments eliminate the option to report other comprehensive income and its components in the statement of changes in stockholders' equity and require an entity to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements. The amendments to FASB ASC 220 were effective for interim and annual periods beginning after December 15, 2011 and should be applied retrospectively. The Company adopted this ASU for reporting periods in 2012 and reports the components of net income and the components of other comprehensive income in two separate but consecutive statements. Adoption of this ASU had no impact on the Company's financial position or results of operations.

2. ACQUISITIONS

Beginning in February 2011, the Company entered into agreements to acquire certain leasehold interests located in the Utica Shale in Ohio. Certain of the agreements also granted the Company an exclusive right of first refusal for a period of six months to acquire certain additional tracts leased by the seller. Affiliates of Gulfport initially participated with the Company on a 50/50 basis in the acquisition of all leases described above. On December 17, 2012, Gulfport entered into a definitive agreement with one of the affiliates to purchase approximately 30,000 net acres in the Utica Shale in Eastern Ohio for approximately $302.0 million. On December 19, 2012, the parties amended that agreement to provide for Gulfport's acquisition of approximately 7,000 additional net acres for approximately $70.0 million, resulting in a total purchase price of approximately $372.0 million, subject to certain adjustments. This transaction closed on December 24, 2012. At closing, approximately $53.9 million of the purchase price was placed in escrow pending completion of title review after the closing. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on December 24, 2012 (with a second closing for the underwriters' purchase of 900,000 shares pursuant to their over-allotment option on January 7, 2013). The Company received aggregate net proceeds of approximately $460.7 million from this equity offering, as discussed below in Note 8.

On February 15, 2013, the Company completed an acquisition of approximately 22,000 net acres in the Utica Shale in Eastern Ohio. The purchase price was approximately $220.0 million, subject to certain adjustments. At closing, approximately

$33.6 million of the purchase price was placed in escrow pending completion of title review after the closing. Gulfport funded this acquisition with a portion of the net proceeds from its common stock offering that closed on February 15, 2013. The Company received aggregate net proceeds of approximately $325.8 million from this equity offering. All of the acreage included in these transactions was nonproducing at the time of the applicable transaction and the Company is the operator of all of this acreage, subject to existing development and operating agreements between the parties. These acquisitions excluded the seller's interest in 14 existing wells and 16 proposed future wells together with certain acreage surrounding these wells.

In May 2013, both escrow accounts terminated and an aggregate of $10.0 million was returned to the Company. The balance of the escrow accounts was distributed to the seller based on the results of the title review.

3. ACCOUNTS RECEIVABLE—RELATED PARTIES

Included in the accompanying consolidated balance sheets as of December 31, 2013 and 2012 are amounts receivable from related parties of the Company. These receivables consist primarily of amounts billed by the Company to related parties as operator of such parties' Ohio and Colorado oil and natural gas properties. At December 31, 2013 and 2012, these receivables totaled $2.6 million and $34.8 million, respectively.

Effective April 1, 2010, the Company entered into an area of mutual interest agreement with Windsor Niobrara LLC ("Windsor Niobrara"), an entity in which Gulfport's former Chairman is the operating member and holds a 10% contingent participating interest, to jointly acquire oil and gas leases on certain lands located in Northwest Colorado for the purpose of exploring, exploiting and producing oil and gas from the Niobrara Formation. The agreement provides that each party must offer the other party the right to participate in such acquisitions on a 50%/50% basis. The parties also agreed, subject to certain exceptions, to share third-party costs and expenses in proportion to their respective participating interests and pay certain other fees as provided in the agreement. In connection with this agreement, Gulfport and Windsor Niobrara also entered into a development agreement, effective as of April 1, 2010, pursuant to which the Company and Windsor Niobrara agreed to jointly develop the contract area, and Gulfport agreed to act as the operator under the terms of a joint operating agreement.

For the year ended December 31, 2011, the Company was reimbursed approximately $66,000 by Orange Leaf Holdings, LLC, a company controlled by Gulfport's prior Chairman, for office space which is included in other income (expense) in the consolidated statements of operations.

4. PROPERTY AND EQUIPMENT

The major categories of property and equipment and related accumulated depletion, depreciation, amortization and impairment as of December 31, 2013 and 2012 are as follows:

	December 31,	
	2013	2012
	(In thousands)	
Oil and natural gas properties	$ 2,477,178	$ 1,611,090
Office furniture and fixtures	6,093	4,476
Building	4,626	3,926
Land	412	260
Total property and equipment	2,488,309	1,619,752
Accumulated depletion, depreciation, amortization and impairment	(784,717)	(665,884)
Property and equipment, net	$ 1,703,592	$ 953,868

No impairment of oil and natural gas properties was required under the ceiling test for the years ended December 31, 2013, 2012 or 2011.

Included in oil and natural gas properties at December 31, 2013 and 2012 is the cumulative capitalization of $47.5 million and $32.6 million in general and administrative costs incurred and capitalized to the full cost pool. General and administrative costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All general and administrative costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized general and administrative costs were approximately $14.9 million, $9.1 million and $5.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The following is a summary of Gulfport's oil and gas properties not subject to amortization as of December 31, 2013:

	Costs Incurred in				
	2013	2012	2011	Prior to 2011	Total
			(in thousands)		
Acquisition costs	$ 342,857	$ 493,981	$ 106,704	$ 1,068	$ 944,610
Exploration costs	—	—	—	—	—
Development costs	—	—	—	—	—
Capitalized interest	5,980	—	—	—	5,980
Total oil and gas properties not subject to amortization	$ 348,837	$ 493,981	$ 106,704	$ 1,068	$ 950,590

The following table summarizes the Company's non-producing properties excluded from amortization by area at December 31, 2013:

	December 31, 2013
	(In thousands)
Colorado	$ 6,054
Bakken	295
Southern Louisiana	542
Ohio	943,654
Other	45
	$ 950,590

At December 31, 2012, approximately $626.3 million of non-producing leasehold costs was not subject to amortization.

During the year ended December 31, 2012, the Company determined that further development of its non-producing leasehold assets located in Belize was not in alignment with its current strategic operating plan, and therefore, recognized a loss on disposal of assets, net of tax, of approximately $3.5 million which is included in discontinued operations on the accompanying consolidated statements of operations for the year ended December 31, 2012.

The Company evaluates the costs excluded from its amortization calculation at least annually. Subject to industry conditions and the level of the Company's activities, the inclusion of most of the above referenced costs into the Company's amortization calculation is expected to occur within three to five years.

A reconciliation of the Company's asset retirement obligation for the years ended December 31, 2013 and 2012 is as follows:

	December 31,	
	2013	2012
	(In thousands)	
Asset retirement obligation, beginning of period	$ 13,275	$ 12,653
Liabilities incurred	3,556	2,195
Liabilities settled	(2,465)	(2,271)
Accretion expense	717	698
Asset retirement obligation as of end of period	15,083	13,275
Less current portion	795	60
Asset retirement obligation, long-term	$ 14,288	$ 13,215

On May 7, 2012, the Company entered into a contribution agreement with Diamondback. Under the terms of the contribution agreement, the Company agreed to contribute to Diamondback, prior to the closing of the Diamondback initial public offering ("Diamondback IPO"), all its oil and natural gas interests in the Permian Basin (the "Contribution"). The Contribution was completed on October 11, 2012. At the closing of the Contribution, Diamondback issued to the Company (i) 7,914,036 shares of Diamondback common stock and (ii) a promissory note for $63.6 million, which was repaid to the Company at the closing of the Diamondback IPO on October 17, 2012. This aggregate consideration was subject to a post-closing cash adjustment based on changes in the working capital, long-term debt and certain other items of Diamondback O&G LLC, formerly Windsor Permian LLC ("Diamondback O&G"), as of the date of the Contribution. In January 2013, the Company received an additional payment from Diamondback of approximately $18.6 million as a result of this post-closing adjustment. Diamondback O&G is a wholly-owned subsidiary of Diamondback. Under the contribution agreement, the Company is generally responsible for all liabilities and obligations with respect to the contributed properties arising prior to the Contribution and Diamondback is responsible for such liabilities and obligations with respect to the contributed properties arising after the Contribution.

In accordance with the Company's policy under the full cost method of accounting to only recognize a gain or loss upon the disposal of oil and natural gas properties if such dispositions significantly alter the relationship between capitalized costs and proven oil and natural gas reserves, the Company recognized a gain on the sale of its Permian Basin assets of approximately $7.3 million, which is included in the accompanying consolidated statements of operations for the year ended December 31, 2012. In addition, the Company recorded a reduction to its full cost pool of approximately $213.0 million as a result of the Contribution.

In connection with the Contribution, the Company and Diamondback entered into an investor rights agreement under which the Company has the right, for so long as it beneficially owns more than 10% of Diamondback's outstanding common stock, to designate one individual as a nominee to serve on Diamondback's board of directors. Such nominee, if elected to Diamondback's board, will also serve on each committee of the board so long as he or she satisfies the independence and other requirements for service on the applicable committee of the board. So long as the Company has the right to designate a nominee to Diamondback's board and there is no Gulfport nominee actually serving as a Diamondback director, the Company has the right to appoint one individual as an advisor to the board who shall be entitled to attend board and committee meetings. The Company is also entitled to certain information rights and Diamondback granted the Company certain demand and "piggyback" registration rights obligating Diamondback to register with the SEC any shares of Diamondback common stock that the Company owns. Immediately upon completion of the Contribution, the Company owned a 35% equity interest in Diamondback, rather than leasehold interests in the Company's Permian Basin acreage. Upon completion of the Diamondback IPO in October 2012, Gulfport owned approximately 21.4% of Diamondback's outstanding common stock. As of December 31, 2013, Gulfport owned approximately 7.2% of Diamondback's outstanding common stock. Following the Contribution, the Company has accounted for its interest in Diamondback as an equity investment. See Note 5, "Equity Investments - *Diamondback Energy, Inc*."

5. EQUITY INVESTMENTS

Investments accounted for by the equity method consist of the following as of December 31, 2013 and 2012:

	Approximate Ownership %	Carrying Value December 31, 2013	Carrying Value December 31, 2012	(Income) loss from equity method investments For the Year Ended December 31, 2013	2012	2011
		(In thousands)				
Investment in Tatex Thailand II, LLC	23.5%	$ —	$ 203	$ (343)	$ 7	$ 7
Investment in Tatex Thailand III, LLC	17.9%	10,774	8,657	254	251	172
Investment in Grizzly Oil Sands ULC	24.9999%	191,473	172,766	2,999	1,512	1,592
Investment in Bison Drilling and Field Services LLC	40.0%	12,318	13,518	3,533	373	(357)
Investment in Muskie Proppant LLC	25.0%	7,544	7,320	1,975	1,031	4
Investment in Timber Wolf Terminals LLC	50.0%	1,001	878	(6)	122	—
Investment in Windsor Midstream LLC	22.5%	10,632	9,503	(1,125)	(663)	—
Investment in Stingray Pressure Pumping LLC	50.0%	19,624	13,265	(818)	1,235	—
Investment in Stingray Cementing LLC	50.0%	3,291	3,110	93	159	—
Investment in Blackhawk Midstream LLC	50.0%	—	—	673	436	—
Investment in Stingray Logistics LLC	50.0%	903	947	51	36	—
Investment in Diamondback Energy, Inc.	7.2%	178,708	151,317	(220,129)	(12,821)	—
Investment in Stingray Energy Services LLC	50.0%	3,800	—	(215)	—	—
		$ 440,068	$ 381,484	$(213,058)	$ (8,322)	$ 1,418

The tables below summarize financial information for the Company's equity investments, excluding Diamondback, as of December 31, 2013 and 2012.

Summarized balance sheet information:

	December 31, 2013	December 31, 2012
	(In thousands)	
Current assets	$ 84,107	$ 68,459
Noncurrent assets	$ 1,107,579	$ 887,884
Current liabilities	$ 112,406	$ 74,308
Noncurrent liabilities	$ 110,095	$ 23,521

Summarized results of operations:

	December 31, 2013	2012	2011
		(In thousands)	
Gross revenue	$ 162,401	$ 39,918	$ 16,955
Net loss	$ 17,350	$ 1,943	$ 6,375

Tatex Thailand II, LLC

The Company has an indirect ownership interest in Tatex Thailand II, LLC (“Tatex”). Tatex holds 85,122 of the 1,000,000 outstanding shares of APICO, LLC (“APICO”), an international oil and gas exploration company. APICO has a reserve base located in Southeast Asia through its ownership of concessions covering approximately 243,000 acres which includes the Phu Horm Field.

Tatex Thailand III, LLC

The Company has an ownership interest in Tatex Thailand III, LLC ("Tatex III"). Tatex III owns a concession covering approximately 245,000 acres in Southeast Asia. During the year ended December 31, 2013 and 2012, the Company paid cash calls of $2.4 million and $0.6 million, respectively.

Grizzly Oil Sands ULC

The Company, through its wholly owned subsidiary Grizzly Holdings Inc. ("Grizzly Holdings"), owns an interest in Grizzly Oil Sands ULC ("Grizzly"), a Canadian unlimited liability company. The remaining interest in Grizzly are owned by Grizzly Oil Sands Inc. ("Oil Sands"), an entity owned by certain investment funds managed by Wexford Capital LP ("Wexford"). As of December 31, 2013, Grizzly had approximately 830,000 acres under lease in the Athabasca and Peace River oil sands regions of Alberta, Canada. During the years ended December 31, 2013 and 2012, Gulfport paid $33.9 million and $103.9 million, respectively, in cash calls. Grizzly's functional currency is the Canadian dollar. The Company's investment in Grizzly was decreased by $12.2 million and $0.9 million as a result of a foreign currency translation loss for the years ended December 31, 2013 and 2011, respectively, and increased by $1.4 million as a result of a foreign currency translation gain for the year ended December 31, 2012.

The Company, through Grizzly Holdings, entered into a loan agreement with Grizzly effective January 1, 2008, under which Grizzly borrowed funds from the Company. Borrowed funds initially bore interest at LIBOR plus 400 basis points and had an original maturity date of December 31, 2012. Effective April 1, 2010, the loan agreement was amended to modify the interest rate to 0.69% and change the maturity date to December 31, 2011. Effective October 15, 2010, the loan agreement was further amended to change the maturity date to December 31, 2012. Interest was paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The Company loaned Grizzly approximately $3.2 million during the year ended December 31, 2011. The Company recognized interest income of approximately $0.1 million for the year ended December 31, 2011, which is included in interest income in the consolidated statements of operations. Effective December 7, 2011, Grizzly Holdings Inc., entered into a debt settlement agreement with Grizzly under which Grizzly agreed to satisfy the entire outstanding debt by issuing additional common shares of Grizzly with no effect to the composition of ownership structure of Grizzly. At such date, the Company's investment in Grizzly increased by the total $22.3 million outstanding advances and accrued interest due from Grizzly, the cumulative $0.1 million currency translation loss for the note receivable was adjusted through accumulated other comprehensive income and the note receivable was considered paid in full.

Bison Drilling and Field Services LLC

During 2011, the Company invested in Bison Drilling and Field Services LLC ("Bison"). Bison owns and operates drilling rigs. During the years ended December 31, 2013 and 2012, Gulfport paid $2.3 million and $7.5 million, respectively, in cash calls.

The Company entered into a loan agreement with Bison effective May 15, 2012, under which Bison may borrow funds from the Company. Interest accrues at LIBOR plus 0.28% or 8%, whichever is lower, and shall be paid on a paid-in-kind basis by increasing the outstanding balance of the loan. The loan has a maturity date of January 31, 2015. The Company loaned Bison $1.6 million during the first nine months of 2012, all of which was repaid by Bison during the third quarter of 2012. The Company has made no loans to Bison since that time.

Muskie Proppant LLC

During 2011, the Company invested in Muskie Proppant LLC ("Muskie"), formerly known as Muskie Holdings LLC. Muskie processes and sells sand for use in hydraulic fracturing by the oil and natural gas industry and holds certain rights in a lease covering land in Wisconsin for mining oil and natural gas fracture grade sand. During the years ended December 31, 2013 and 2012, Gulfport paid $2.2 million and $6.2 million, respectively, in cash calls.

The Company entered into a loan agreement with Muskie effective July 1, 2013, under which it loaned Muskie $0.9 million. Interest accrues at the prime rate plus 2.5%. The loan has a maturity date of July 31, 2014. At December 31, 2013, the outstanding balance on the loan is included in notes receivable-related party on the accompanying consolidated balance sheets.

Timber Wolf Terminals LLC

During 2012, the Company invested in Timber Wolf Terminals LLC ("Timber Wolf"). The Company's initial investment during 2012 was $1.0 million. Timber Wolf will operate a crude/condensate terminal and a sand transloading facility in Ohio. During the year ended December 31, 2013, Gulfport paid $0.1 million in cash calls.

Windsor Midstream LLC

During 2012, the Company purchased an ownership interest in Windsor Midstream LLC ("Midstream") at a cost of $7.0 million. Midstream owns a 28.4% interest in MidMar Gas LLC, a gas processing plant in West Texas. During the year ended December 31, 2013, Gulfport paid an immaterial amount in net cash calls to Midstream. During the year ended December 31, 2012, Gulfport paid $1.8 million in cash calls.

Stingray Pressure Pumping LLC

During 2012, the Company invested in Stingray Pressure Pumping LLC ("Stingray Pressure"). Stingray Pressure provides well completion services. During the years ended December 31, 2013 and 2012, the Company paid $1.8 million and $14.5 million, respectively, in cash calls. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Stingray Cementing LLC

During 2012, the Company invested in Stingray Cementing LLC ("Stingray Cementing"). Stingray Cementing provides well cementing services. During the year ended December 31, 2013, the Company did not pay any cash calls related to Stingray Cementing. During the year ended December 31, 2012, the Company paid $3.3 million in cash calls. The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

Blackhawk Midstream LLC

During 2012, the Company invested in Blackhawk Midstream LLC ("Blackhawk"). Blackhawk coordinates gathering, compression, processing and marketing activities for the Company in connection with the development of its Utica Shale acreage. During the years ended December 31, 2013 and 2012, the Company paid $0.7 million and $0.4 million, respectively, in cash calls related to Blackhawk. On January 28, 2014, Blackhawk closed on the sale of its equity interest in Ohio Gathering Company, LLC and Ohio Condensate Company, LLC for a purchase price of $190.0 million, of which $14.3 million was placed in escrow. Gulfport received $84.8 million in net proceeds from this transaction.

Stingray Logistics LLC

During 2012, the Company invested in Stingray Logistics LLC ("Stingray Logistics"). Stingray Logistics provides well services. During the year ended December 31, 2012, the Company paid $1.0 million in cash calls.

Diamondback Energy, Inc.

As noted above in Note 4, on May 7, 2012, the Company entered into a contribution agreement with Diamondback. Following the closing of the Diamondback IPO, the Company owned approximately 21.4% of Diamondback's outstanding common stock for an initial investment in Diamondback of $138.5 million. On June 24, 2013, the Company sold 1,951,781 shares of its Diamondback common stock for net proceeds of $65.1 million in an underwritten public offering in which certain entities controlled by Wexford also participated as selling stockholders. On July 5, 2013, the underwriters purchased an additional 282,755 shares of Diamondback common stock from Gulfport pursuant to an option to purchase additional shares from the selling stockholders granted to the underwriters resulting in net proceeds to the Company of $9.4 million. The shares were sold to the public at $34.75 per share. On November 11, 2013, the Company sold 2,000,000 shares of its Diamondback common stock for net proceeds of $102.8 million in an underwritten public offering. On November 18, 2013, the underwriters purchased an additional 300,000 shares of Diamondback common stock from Gulfport pursuant to an option to purchase additional shares from the selling stockholder granted to the underwriters resulting in net proceeds to the Company of $15.4 million. The shares were sold to the public at $51.39 per share. As of December 31, 2013, the Company owned approximately 7.2% of Diamondback's outstanding common stock.

The Company accounts for its interest in Diamondback as an equity method investment and has elected the fair value option of accounting for this investment. While the investment in Diamondback is below 20% ownership at December 31, 2013, the Company has appointed a member of Diamondback's Board as discussed in Note 4; as the Company continues to have influence through this board seat, the investment in Diamondback will continue to be accounted for as an equity method investment. The Company valued its investment in Diamondback using the quoted closing market price of Diamondback's stock on December 31, 2013 of $52.88 per share multiplied by the number of outstanding shares of Diamondback's stock held by the Company. The Company recognized an aggregate gain of approximately $220.1 million and $12.8 million on its investment in Diamondback for years ended December 31, 2013 and 2012, respectively, which is included in (income) loss from equity method investments in the consolidated statements of operations.

The Company has determined that for the periods presented in its consolidated financial statements, Diamondback has met the conditions of a significant subsidiary under Rule 1-02(w) of Regulation S-X, for which the Company is required, pursuant to Rule 3-09 of Regulation S-X, to attach separate financial statements as exhibits to its Annual Report on Form 10-K.

Stingray Energy Services LLC

During 2013, the Company invested in Stingray Energy Services LLC ("Stingray Energy") at a cost of $2.9 million. Stingray Energy provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites.The (income) loss from equity method investments presented in the table above reflects any intercompany profit eliminations.

6. OTHER ASSETS

Other assets consist of the following as of December 31, 2013 and 2012:

	December 31,	
	2013	2012
	(In thousands)	
Plugging and abandonment escrow account on the WCBB properties (Note 16)	$ 3,105	$ 3,113
Certificates of Deposit securing letter of credit	275	275
Prepaid drilling costs	526	515
Loan commitment fees	9,341	9,388
Derivative receivable	4,493	—
Deposits	34	4
Other	77	—
	$ 17,851	$ 13,295

7. LONG-TERM DEBT

Long-term debt consisted of the following items as of December 31, 2013 and 2012:

	December 31,	
	2013	2012
	(In thousands)	
Revolving credit agreement (1)	$ —	$ —
Building loans (2)	1,995	2,143
7.75% senior unsecured notes due 2020 (3)	300,000	300,000
Unamortized original issue (discount) premium, net (4)	(2,808)	(3,105)
Less: current maturities of long term debt	(159)	(150)
Debt reflected as long term	$ 299,028	$ 298,888

Maturities of long-term debt (excluding premiums and discounts) as of December 31, 2013 are as follows:

		(In thousands)
2014	$	159
2015		168
2016		1,668
2017		—
2018		300,000
Thereafter		—
Total	$	301,995

The Company capitalized approximately $7.1 million in interest expense to undeveloped oil and natural gas properties during the year ended December 31, 2013. There was no interest expense capitalized during the year ended December 31, 2012.

(1) On September 30, 2010, the Company entered into a $100.0 million senior secured revolving credit agreement with The Bank of Nova Scotia, as administrative agent and letter of credit issuer and lead arranger, and Amegy Bank National Association ("Amegy Bank"). The revolving credit facility initially matured on September 30, 2013 and had an initial borrowing base availability of $50.0 million, which was increased to $65.0 million effective December 24, 2010. The credit agreement is secured by substantially all of the Company's assets. The Company's wholly-owned subsidiaries guaranteed the obligations of the Company under the credit agreement.

On May 3, 2011, the Company entered into a first amendment to the revolving credit agreement with The Bank of Nova Scotia, Amegy Bank, KeyBank National Association ("KeyBank") and Société Générale. Pursuant to the terms of the first amendment, KeyBank and Société Générale were added as additional lenders, the maximum amount of the facility was increased to $350.0 million, the borrowing base was increased to $90.0 million, certain fees and rates payable by the Company under the credit agreement were decreased, and the maturity date was extended until May 3, 2015. On October 31, 2011, the Company entered into additional amendments to its revolving credit facility pursuant to which, among other things, the borrowing base under this facility was increased to $125.0 million.

Effective May 2, 2012, the Company entered into a fourth amendment to its revolving credit facility under which, among other things, the borrowing base was increased to $155.0 million and Credit Suisse, Deutsche Bank Trust Company Americas and Iberiabank were added as additional lenders and Société Générale left the bank group.

On October 9, 2012 and October 17, 2012, the Company entered into a fifth amendment and a sixth amendment, respectively, to the revolving credit agreement. The fifth amendment modified certain covenants in the credit agreement to permit the Company to issue senior unsecured notes in an aggregate principal amount of up to $300.0 million and provided for a reduction in the borrowing base to an amount to be determined upon the completion of any senior unsecured notes issuance. The sixth amendment lowered the applicable rate set forth in the credit agreement (i) from a range of 1.00% to 1.75% to a range of 0.75% to 1.50% for the base rate loans and (ii) from a range of 2.00% to 2.75% to a range of 1.75% to 2.50% for the eurodollar rate loans and letters of credit. The sixth amendment lowered the commitment fees for Level 1 and Level 2 usage levels, in each case, from 0.50% per annum to 0.375% per annum. Also, effective as of October 17, 2012, in connection with the Company's completion of the offering of $250.0 million 7.75% senior unsecured notes due 2020, (the "October Notes"), the repayment of all outstanding amounts under the revolving credit agreement with the proceeds of the October Notes, and the contribution of Gulfport's oil and natural gas interests in the Permian Basin to Diamondback discussed in Notes 4 and 5 above, Gulfport's borrowing base under the credit agreement was reduced to $45.0 million until the next borrowing base redetermination. In conjunction with the lowering of the borrowing base in October 2012, the company expensed a proportional amount of the unamortized loan fees associated with the revolving credit facility totaling approximately $1.1 million, which is included in interest expense on the accompanying consolidated statements of operations.

On December 18, 2012, the Company entered into a seventh amendment to the revolving credit agreement under which the Company was permitted to issue $50.0 million 7.75% senior unsecured notes due 2020 (the "December Notes") under the same indenture as the October Notes (collectively, the "Notes"), and upon the issuance of the December Notes, the borrowing base under the revolving credit agreement was reduced from $45.0 million to $40.0 million until the next borrowing base redetermination. In conjunction with the lowering of the borrowing base in December 2012, the Company expensed a proportional amount of unamortized loan fees associated with the revolving credit facility totaling approximately $0.1 million, which is included in interest expense on the accompanying consolidated statements of operations.

On June 6, 2013, the Company entered into an eighth amendment to the revolving credit agreement. The eighth amendment lowered the applicable rate set forth in the revolving credit agreement (i) from a range of 1.75% to 2.50% to a range of 1.50% to 2.50% for eurodollar rate loans and (ii) from a range of 0.75% to 1.50% to a range of 0.50% to 1.50% for base rate loans. Additionally, the eighth amendment extended the maturity date from May 3, 2015 to June 6, 2018, provided for an increase in the borrowing base from $40.0 million to $50.0 million, and amended certain other provisions.

On December 27, 2013, the Company entered into an Amended and Restated Credit Agreement with The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and other lenders, which amends and restates in its entirety the Company's existing credit agreement, dated as of September 30, 2010, as amended. The Amended and Restated Credit Agreement provides for an increase in the maximum facility amount from $350.0 million to $1.5 billion, with an increase in borrowing base availability as of December 27, 2013 from $50.0 million to $150.0 million. The Amended and Restated Credit Agreement matures on June 6, 2018. As of December 31, 2013, the Company had no borrowings outstanding under the revolving credit agreement. At December 31, 2013, the total available funds under our revolving credit agreement, including a reduction for a $6.4 million letter of credit in effect, was $143.6 million.

Advances under the credit agreement, as amended, may be in the form of either base rate loans or eurodollar loans. The interest rate for base rate loans is equal to (1) the applicable rate, which ranges from 0.50% to 1.50%, plus (2) the highest of: (a) the federal funds rate plus 0.50%, (b) the rate of interest in effect for such day as publicly announced from time to time by agent as its "prime rate," and (c) the eurodollar rate for an interest period of one month plus 1.00%. The interest rate for eurodollar loans is equal to (1) the applicable rate, which ranges from 1.50% to 2.50%, plus (2) the London interbank offered rate that appears on Reuters Screen LIBOR01 Page for deposits in U.S. dollars, or, if such rate is not available, the offered rate on such other page or service that displays the average British Bankers Association Interest Settlement Rate for deposits in U.S. dollars, or, if such rate is not available, the average quotations for three major New York money center banks of whom the agent shall inquire as the "London Interbank Offered Rate" for deposits in U.S. dollars.

The credit agreement contains customary negative covenants including, but not limited to, restrictions on the Company's and its subsidiaries' ability to:

- incur indebtedness;
- grant liens;
- pay dividends and make other restricted payments;
- make investments;
- make fundamental changes;
- enter into swap contracts and forward sales contracts;
- dispose of assets;
- change the nature of their business; and
- enter into transactions with affiliates.

The negative covenants are subject to certain exceptions as specified in the credit agreement. The credit agreement also contains certain affirmative covenants, including, but not limited to the following financial covenants:

(i) the ratio of funded debt to EBITDAX (net income, excluding any non-cash revenue or expense associated with swap contracts resulting from ASC 815, plus without duplication and to the extent deducted from revenues in determining net income, the sum of (a) the aggregate amount of consolidated interest expense for such period, (b) the aggregate amount of income, franchise, capital or similar tax expense (other than ad valorem taxes) for such period, (c) all amounts attributable to depletion, depreciation, amortization and asset or goodwill impairment or writedown for such period, (d) all other non-cash charges, (e) non-cash losses from minority investments, (f) actual cash distributions received from minority investments, (g) to the extent actually reimbursed by insurance, expenses with respect to liability on casualty events or business interruption, and (h) all reasonable transaction expenses related to dispositions and acquisitions of assets, investments and debt and equity offerings, and less non-cash income attributable to equity income from minority investments) for a twelve-month period may not be greater than 2.00 to 1.00; and

(ii) the ratio of EBITDAX to interest expense for a twelve-month period may not be less than 3.00 to 1.00.

The Company was in compliance with all covenants at December 31, 2013.

(2) In March 2011, the Company entered into a new building loan agreement for the office building it occupies in Oklahoma City, Oklahoma. The new loan agreement refinanced the $2.4 million outstanding under the previous building loan agreement. The new agreement matures in February 2016 and bears interest at the rate of 5.82% per annum. The new building loan requires monthly interest and principal payments of approximately $22,000 and is collateralized by the Oklahoma City office building and associated land.

(3) On October 17, 2012, the Company issued $250.0 million in aggregate principal amount of October Notes to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act, (the "October Notes Offering") under an indenture among the Company, its subsidiary guarantors and Wells Fargo Bank, National Association, as the trustee, (the "senior note indenture"). On December 21, 2012, the Company issued an additional $50.0 million in aggregate principal amount of December Notes to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to certain non-U.S. persons in accordance with Regulation S under the Securities Act ("the December Notes Offering"). The December Notes were issued as additional securities under the senior note indenture. The October Notes Offering and the December Notes Offering are collectively referred to as the "Notes Offerings". The Company used a portion of the net proceeds from the October Notes Offering to repay all amounts outstanding at such time under its revolving credit facility. The Company used the remaining net proceeds of October Notes Offering and the net proceeds of the December Notes Offering for general corporate purposes, which included funding a portion of its 2013 capital development plan.

Under the senior note indenture, interest on the Notes accrues at a rate of 7.75% per annum on the outstanding principal amount from October 17, 2012, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2013. The Notes are the Company's senior unsecured obligations and rank equally in the right of payment with all of the Company's other senior indebtedness and senior in right of payment to any future subordinated indebtedness. All of the Company's existing and future restricted subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt guarantee the Notes; provided, however, that the Notes are not guaranteed by Grizzly Holdings, Inc. and will not be guaranteed by any of the Company's future unrestricted subsidiaries. The Company may redeem some or all of the Notes at any time on or after November 1, 2016, at the redemption prices listed in the senior note indenture. Prior to November 1, 2016, the Company may redeem the Notes at a price equal to 100% of the principal amount plus a “make-whole” premium. In addition, prior to November 1, 2015, the Company may redeem up to 35% of the aggregate principal amount of the Notes with the net proceeds of certain equity offerings, provided that at least 65% of the aggregate principal amount of the Notes initially issued remains outstanding immediately after such redemption.

(4) The October Notes were issued at a price of 98.534% resulting in a gross discount of $3.7 million and an effective rate of 8.000%. The December Notes were issued at a price of 101.000% resulting in a gross premium of $0.5 million and an effective rate of 7.531%. The premium and discount are being amortized using the effective interest method.

Interest Expense

The following schedule shows the components of interest expense at December 31, 2013 and 2012 :

	December 31,		
	2013	**2012**	**2011**
		(In thousands)	
Cash paid for interest	$ 24,270	$ 1,404	$ 963
Change in accrued interest	(969)	4,155	(132)
Write-off of deferred loan costs	—	1,143	—
Capitalized interest	(7,132)	—	—
Amortization of loan costs	1,012	640	540
Amortization of note discount and premium	298	59	—
Other	11	57	29
Total interest expense	$ 17,490	$ 7,458	$ 1,400

8. COMMON STOCK OPTIONS, WARRANTS AND CHANGES IN CAPITALIZATION

Options

The Company sponsors the 1999 Stock Option Plan (the "Plan"), which is administered by the Compensation Committee (the "Committee") of the Board of Directors of the Company. Under the terms of the Plan, the Committee could determine: to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting period of such options and the exercisable period of such options. Eligible participants are defined as all directors of the Company, all officers of the Company and all key employees of the Company with a customary work week of at least 40 hours in the employ of the Company. The maximum number of shares for which options could be granted under the Plan, as adjusted for changes in capitalization which have taken place since the Plan's adoption, was 883,000. The Company has granted 627,337 options for the purchase of shares of the Company's common stock under the Plan as of December 31, 2013. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

The Company replaced the Plan in January 2005 with the 2005 Stock Incentive Plan ("2005 Plan"), which is administered by the Committee. Under the terms of the 2005 Plan, the Committee may determine when options shall be granted, to which eligible participants options shall be granted, the number of shares covered by such options, the purchase price or exercise price of such options, the vesting periods of such options and the exercisable period of such options. Eligible participants are defined as employees, consultants, and directors of the Company.

On April 20, 2006, the Company amended and restated the 2005 Plan to (i) include (a) incentive stock options, (b) nonstatutory stock options, (c) restricted awards (restricted stock and restricted stock units), (d) performance awards and (e) stock appreciation rights and (ii) increase the maximum aggregate amount of common stock that may be issued under the 2005 Plan from 1,904,606 shares to 3,000,000 shares, including the 627,337 shares underlying options granted to employees under the Plan prior to adoption of the 2005 Plan. As of December 31, 2013, the Company has granted 997,269 options for the purchase of shares of the Company's common stock under the 2005 Plan. No additional securities will be issued under the Plan other than upon exercise of options that are outstanding.

On April 19, 2013, the Company amended and restated the 2005 Plan with the 2013 Restated Stock Incentive Plan ("2013 Plan"). The 2013 Plan increased the numbers of shares that may be awarded from 3,000,000 to 7,500,000 shares, including the 627,337 shares underlaying options granted to employees under the Plan. The shares of stock issued once the options are exercised will be from authorized but unissued common stock.

Sale of Common Stock

On March 30, 2011, the Company completed the sale of an aggregate of 2,760,000 shares of its common stock in an underwritten public offering at a public offering price of $32.00 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $84.3 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used the net proceeds from the equity offering to fund the Company's acquisition of leases in the Utica Shale as discussed in Note 2 and for general corporate purposes. Pending the application of the Company's net proceeds for such purposes, the Company repaid all of its outstanding indebtedness under its revolving credit agreement.

On July 15, 2011, the Company completed the sale of an aggregate of 3,450,000 shares of its common stock in an underwritten public offering at a public offering price of $28.75 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $94.7 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of the net proceeds from the equity offering to fund the Company's acquisition of leases in the Utica Shale as discussed in Note 2 and for general corporate purposes. Pending the application of the Company's net proceeds for such purposes, the Company repaid all of its outstanding indebtedness under its revolving credit agreement.

On December 5, 2011, the Company completed the sale of an aggregate of 4,600,000 shares of its common stock in an underwritten public offering at a public offering price of $29.00 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $128.0 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used the proceeds to fund capital expenditures associated with drilling, development and infrastructure, principally in the Utica Shale in Ohio and for general corporate purposes.

On December 24, 2012, the Company completed the sale of an aggregate of 11,750,000 shares of its common stock in an underwritten public offering (including the partial exercise of a 1,650,000 share over-allotment option granted to the underwriters, which option was initially exercised to the extent of 750,000 shares) at a public offering price of $38.00 per share less the underwriting discount. The underwriters subsequently exercised their option to purchase the remaining 900,000 additional shares of common stock subject to the over-allotment option in a second closing, which occurred on January 7, 2013. The Company received aggregate net proceeds from both closings of approximately $460.7 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of these net proceeds to fund the acquisition of approximately 37,000 net acres in the Utica Shale in Eastern Ohio, as described above in Note 2, and for general corporate purposes, including the funding of a portion of its 2013 capital development plan.

On February 15, 2013, the Company completed the sale of an aggregate of 8,912,500 shares of its common stock in an underwritten public offering at a public offering price of $38.00 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $325.8 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company used a portion of the net proceeds from this equity offering to fund its acquisition of additional Utica Shale acreage as described in Note 2, and the balance for general corporate purposes, including the funding of a portion of its 2013 capital development plan.

On November 13, 2013, the Company completed the sale of an aggregate of 7,475,000 shares of its common stock in an underwritten public offering at a public offering price of $56.75 per share less the underwriting discount. The Company received aggregate net proceeds of approximately $408.0 million from the sale of these shares after deducting the underwriting discount and before offering expenses. The Company has used and intends to continue to use the net proceeds from this equity offering for general corporate purposes, which may include expenditures associated with its 2014 drilling program and additional acreage acquisitions in the Utica Shale.

Private Placement Offering

In March 2002, the Company completed a private placement offering of 10,000 units. Each unit consisted of (i) one share of Cumulative Preferred Stock, Series A, of the Company (the "Preferred") and (ii) a warrant to purchase up to 250 shares of common stock, par value $0.01 per share, of the Company (the "Warrants"). Holders of the Preferred were entitled to receive dividends at the rate of 12% of the liquidation preference per annum payable quarterly in cash or, at the option of the Company for all quarters ending on or prior to March 31, 2004, payable in whole or in part in additional shares of Preferred at the rate of 15% of the liquidation preference per annum. All Preferred shares were redeemed in 2005.

The 2,322,962 Warrants issued had a term of 10 years and a current exercise price of $1.19 per share of common stock subject to adjustment. The Company granted to holders of the Warrants certain demand and piggyback registration rights with respect to shares of common stock issuable upon exercise of the Warrants. The 8,875 unexercised warrants expired on March 31, 2012.

9. STOCK-BASED COMPENSATION

During the years ended December 31, 2013, 2012 and 2011 the Company's stock-based compensation cost was $10.5 million, $4.7 million and $1.3 million, respectively, of which the Company capitalized $4.2 million, $1.9 million and $0.5 million, respectively, relating to its exploration and development efforts.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option valuation model. Expected volatilities are based on the historical volatility of the market price of Gulfport's common stock over a period of time ending on the grant date. Based upon the historical experience of the Company, the expected term of options granted is equal to the vesting period plus one year. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of the grant. The 2005 Plan provides that all options must have an exercise price not less than the fair value of the Company's common stock on the date of the grant.

No stock options were issued during the years ended December 31, 2013, 2012 and 2011.

The Company has not declared dividends and does not intend to do so in the foreseeable future, and thus did not use a dividend yield. In each case, the actual value that will be realized, if any, depends on the future performance of the common stock and overall stock market conditions. There is no assurance that the value an optionee actually realizes will be at or near the value estimated using the Black-Scholes model.

A summary of the status of stock options and related activity for the years ended December 31, 2013, 2012 and 2011 is presented below:

	Shares	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)
Options outstanding at December 31, 2010	458,241	$ 7.23	4.48	$ 6,621
Granted	—	—		
Exercised	(102,000)	9.74		2,308
Forfeited/expired	—	—		
Options outstanding at December 31, 2011	356,241	6.51	3.41	$ 8,172
Granted	—	—		
Exercised	(21,000)	8.80		628
Forfeited/expired	—	—		
Options outstanding at December 31, 2012	335,241	6.37	2.39	$ 10,678
Granted	—	—		
Exercised	(125,000)	11.20		4,797
Forfeited/expired	—	—		
Options outstanding at December 31, 2013	210,241	$ 3.50	1.07	$ 12,538
Options exercisable at December 31, 2013	210,241	$ 3.50	1.07	$ 12,538

The following table summarizes information about the stock options outstanding at December 31, 2013:

Exercise Price	Number Outstanding	Weighted Average Remaining Life (in years)	Number Exercisable
$ 3.36	205,241	1.06	205,241
$ 9.07	5,000	1.69	5,000
	210,241		210,241

The following table summarizes restricted stock activity for the twelve months ended December 31, 2013, 2012 and 2011:

	Number of Unvested Restricted Shares	Weighted Average Grant Date Fair Value
Unvested shares as of December 31, 2010	113,386	$ 11.72
Granted	153,332	31.15
Vested	(63,370)	12.87
Forfeited	—	—
Unvested shares as of December 31, 2011	203,348	$ 26.02
Granted	196,832	$ 35.87
Vested	(135,015)	29.59
Forfeited	(19,334)	26.81
Unvested shares as of December 31, 2012	245,831	$ 31.88
Granted	463,952	$ 50.00
Vested	(237,646)	41.79
Forfeited	(8,500)	38.54
Unvested shares as of December 31, 2013	463,637	$ 44.80

Unrecognized compensation expense as of December 31, 2013 related to outstanding stock options and restricted shares was $19.2 million. The expense is expected to be recognized over a weighted average period of 1.65 years.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amounts on the accompanying consolidated balance sheet for cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and current debt are carried at cost, which approximates market value due to their short-term nature. Long-term debt related to the building loan is carried at cost, which approximates market value based on the borrowing rates currently available to the Company with similar terms and maturities.

At December 31, 2013, the carrying value of the outstanding debt represented by the Notes was $297.2 million, including the remaining unamortized discount of approximately $3.2 million related to the October Notes and the remaining unamortized premium of approximately $0.4 million related to the December Notes. Based on the quoted market price, the fair value of the Notes was determined to be approximately $320.8 million at December 31, 2013.

The fair value of the derivative instruments is computed based on the difference between the prices provided by the fixed-price contracts and forward market prices as of the specified date, as adjusted for basis differentials, and for the Company's swaptions, market implied volatilities of the underlying commodity are also evaluated. Forward market prices for oil and natural gas are dependent upon supply and demand factors in such forward market and are subject to significant volatility.

11. INCOME TAXES

The income tax provision for continuing operations consists of the following:

	2013	2012	2011
		(In thousands)	
Current:			
State	$ 6,860	$ 84	$ —
Federal	6,325	646	282
Deferred:			
State	7,385	2,214	—
Federal	77,566	23,419	(372)
Total income tax expense (benefit) provision from continuing operations	$ 98,136	$ 26,363	$ (90)

A reconciliation of the statutory federal income tax amount to the recorded expense follows:

	2013	2012	2011
		(In thousands)	
Income from continuing operations before federal income taxes	$ 251,328	$ 98,199	$ 108,332
Expected income tax at statutory rate	87,965	34,370	37,916
State income taxes	9,297	1,493	4,227
Other differences	874	292	(146)
Changes in valuation allowance	—	(9,792)	(42,087)
Income tax expense (benefit) recorded for continuing operations	$ 98,136	$ 26,363	$ (90)

The tax effects of temporary differences and net operating loss carryforwards, which give rise to deferred tax assets and liabilities at December 31, 2013, 2012 and 2011 are estimated as follows:

	2013	2012	2011
		(In thousands)	
Deferred tax assets:			
Net operating loss carryforward	$ 1,462	$ 1,513	$ 40,880
FASB ASC 718 compensation expense	634	762	520
Investment in pass through entities	—	—	78
AMT credit	7,968	1,643	1,000
Non-oil and gas property basis difference	—	—	103
Charitable contributions carryover	25	5	3
Unrealized loss on hedging activities	8,540	3,836	—
Foreign tax credit carryforwards	2,074	2,074	—
State net operating loss carryover	4,408	4,315	6,410
Total deferred tax assets	25,111	14,148	48,994
Valuation allowance for deferred tax assets	(4,743)	(4,629)	(12,347)
Deferred tax assets, net of valuation allowance	20,368	9,519	36,647
Deferred tax liabilities:			
Oil and gas property basis difference	72,173	15,049	35,637
Investment in pass through entities	8,799	3,618	—
Non-oil and gas property basis difference	249	227	—
Investment in nonconsolidated affiliates	46,495	9,232	—
Unrealized gain on hedging activities	—	—	10
Total deferred tax liabilities	127,716	28,126	35,647
Net deferred tax asset (liability)	$ (107,348)	$ (18,607)	$ 1,000

The Company has an available federal tax net operating loss carryforward estimated at approximately $4.2 million as of December 31, 2013. This carryforward will begin to expire in the year 2023. Based upon the December 31, 2013 and 2012 net deferred tax liability position of the Company's oil and gas assets, management believes that this is a positive source of evidence to utilize the carryforward before it expires. Therefore, a valuation allowance has not been provided at December 31, 2013 and 2012. A valuation allowance has been provided at December 31, 2011 because it was management’s belief at that time, based upon the Company’s past history of no taxable income and future projections of no taxable income during the carryforward period, it was more likely than not that the net deferred tax assets would not be realized. The Company also has state net operating loss carryovers of $84.8 million from Louisiana that will begin to expire in 2014, alternative minimum tax credits of $8.0 million with no expiration date and federal foreign tax credit carryovers of $2.1 million which begin to expire in 2017. The Company has recorded a valuation allowance of $4.7 million related to state net operating loss carryovers and foreign tax credit carryovers as the carryovers may not be utilized based upon a more likely than not basis.

In 2012, the Diamondback Contribution generated an estimated $61.9 million taxable gain. As a result, the Company recognized $9.8 million of its deferred tax assets which had previously been subject to a valuation allowance. The Company also recognized $25.6 million of deferred tax expense in 2012 primarily due to the utilization of prior net operating losses from the Diamondback Contribution gain. In 2013, the sale of Diamondback common shares generated $120.0 million taxable gain resulting in deferred tax expense of $35.7 million and current tax expense of $13.2 million. The Company's current federal tax expense in 2013 and 2012 is primarily attributable to alternative minimum tax.

12. EARNINGS PER SHARE

Reconciliations of the components of basic and diluted net income per common share are presented in the tables below:

	For the Year Ended December 31,								
	2013			2012			2011		
	Income	Shares	Per Share	Income	Shares	Per Share	Income	Shares	Per Share
	(In thousands, except share data)								
Basic:									
Net income	$ 153,192	77,375,683	$ 1.98	$ 68,371	55,933,354	$ 1.22	$ 108,422	48,754,840	$ 2.22
Effect of dilutive securities:									
Stock options and awards	—	485,963		—	484,134		—	452,123	
Diluted:									
Net income	$ 153,192	77,861,646	$ 1.97	$ 68,371	56,417,488	$ 1.21	$ 108,422	49,206,963	$ 2.20

There were no potential shares of common stock that were considered anti-dilutive for the years ended December 31, 2013, 2012 and 2011.

13. HEDGING ACTIVITIES

Oil Price Hedging Activities

The Company seeks to reduce its exposure to unfavorable changes in oil and natural gas prices, which are subject to significant and often volatile fluctuation, by entering into fixed price swaps. These contracts allow the Company to predict with greater certainty the effective oil and natural gas prices to be received for hedged production and benefit operating cash flows and earnings when market prices are less than the fixed prices provided in the contracts. However, the Company will not benefit from market prices that are higher than the fixed prices in the contracts for hedged production.

The Company accounts for its oil and natural gas derivative instruments as cash flow hedges for accounting purposes under FASB ASC 815 and related pronouncements. All derivative contracts are marked to market each quarter end and are included in the accompanying consolidated balance sheets as derivative assets and liabilities.

During 2012 and 2013, the Company entered into fixed price swap and swaption contracts for 2013 through 2016 with four financial institutions. The Company's fixed price swap contracts are tied to the commodity prices on the International Petroleum Exchange ("IPE") and NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on the IPE for Brent Crude and the NYMEX WTI for oil and on the NYMEX Henry Hub for natural gas. At December 31, 2013, the Company had the following fixed price swaps in place:

	Daily Volume (Bbls/day)	Weighted Average Price
January - March 2014	4,000	$ 104.75
April - December 2014	2,000	$ 101.50

	Daily Volume (MMBtu/day)	Weighted Average Price
January 2014	65,000	$ 4.04
February - December 2014	105,000	$ 4.01
January - December 2015	125,000	$ 4.03
January - March 2016	105,000	$ 4.04
April 2016	95,000	$ 4.04

At December 31, 2013 the fair value of derivative assets and liabilities related to the fixed price swaps and swaptions was as follows:

	(In thousands)
Short-term derivative instruments - asset	$ 324
Long-term derivative instruments - asset	$ 521
Short-term derivative instruments - liability	$ 12,280
Long-term derivative instruments - liability	$ 11,366

At December 31, 2012 the fair value of derivative assets and liabilities related to the fixed price swaps and swaptions was as follows:

	(In thousands)
Short-term derivative instruments - asset	$ 664
Short-term derivative instruments - liability	$ 10,442

All fixed price swaps and swaptions have been executed in connection with the Company's oil and natural gas price hedging program. For fixed price swaps qualifying as cash flow hedges pursuant to FASB ASC 815, the realized contract price is included in oil and gas sales in the period for which the underlying production was hedged.

For derivatives designated as cash flow hedges and meeting the effectiveness guidelines of FASB ASC 815, changes in fair value are recognized in accumulated other comprehensive income (loss) until the hedged item is recognized in earnings. Amounts reclassified out of accumulated other comprehensive income (loss) into earnings as a component of oil and condensate sales for the years ended December 31, 2013 and 2012 are presented below.

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Reduction to oil and condensate sales	$ (9,779)	$ (1,517)	$ (4,720)

At December 31, 2013, no amounts related to fixed price swaps remain in accumulated other comprehensive income (loss).

The following table presents the balances of the Company's cumulative hedging activities included in other comprehensive income.

		(In thousands)
December 31, 2010	$	(4,720)
December 31, 2011	$	1,576
December 31, 2012	$	(9,660)
December 31, 2013	$	—

Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value resulting from ineffectiveness is recognized immediately in earnings. The Company recognized a loss of $18.2 million related to hedge ineffectiveness for the year ended December 31, 2013, which is included in oil and condensate and gas sales in the consolidated statements of operations. This loss was comprised of a loss of $9.1 million related to hedge ineffectiveness and a loss of $9.1 million related to the amortization of other comprehensive income for the year ended December 31, 2013. The Company recognized a loss of $0.1 million related to hedge ineffectiveness for the year ended December 31, 2012, which is included in oil and condensate sales in the consolidated statements of operations. The Company recognized an immaterial gain related to hedge ineffectiveness for the year ended December 31, 2011, which is included in oil and condensate sales in the consolidated statements of operations.

The Company delivered approximately 48% of its 2013 production under fixed price swaps.

14. FAIR VALUE MEASUREMENTS

The Company records certain financial and non-financial assets and liabilities on the balance sheet at fair value in accordance with FASB ASC 820. FASB ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. The statement establishes market or observable inputs as the preferred sources of values, followed by assumptions based on hypothetical transactions in the absence of market inputs. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Level 2 – Quoted prices in active markets for similar assets and 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.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The following tables summarize the Company's financial and non-financial liabilities by FASB ASC 820 valuation level as of December 31, 2013 and 2012:

	December 31, 2013					
	Level 1		Level 2		Level 3	
	(In thousands)					
Assets:						
Fixed price swaps	$	—	$	845	$	—
Equity investment in Diamondback		178,708		—		—
Liabilities:						
Fixed price swaps and swaptions	$	—	$	23,646	$	—

	December 31, 2012					
	Level 1		Level 2		Level 3	
	(In thousands)					
Assets:						
Fixed price swaps	$	—	$	664	$	—
Equity investment in Diamondback		151,317		—		—
Liabilities:						
Fixed price swaps	$	—	$	10,442	$	—

The estimated fair value of the Company's fixed price swap contracts and swaptions were based upon forward commodity prices based on quoted market prices, adjusted for differentials, and for the Company's swaptions, market implied volatilities of the underlying commodity were also evaluated. See Note 13 for further discussion of the Company's hedging activities. The estimated fair value of the Company's equity investment in Diamondback was based upon the public closing share price of Diamondback's common stock as of December 31, 2013.

The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, "*Asset Retirement and Environmental Obligations*" ("FASB ASC 410"). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 4 for further discussion of the Company's asset retirement obligations. Asset retirement obligations incurred during the year ended December 31, 2013 were approximately $3.6 million.

15. RELATED PARTY TRANSACTIONS

In the ordinary course of business, the Company conducts business activities with certain related parties.

Diamondback operates the Permian Basin wells included in the Contribution as discussed above in Note 4. At December 31, 2012, the Company owed Diamondback approximately $0.3 million related to reimbursement for services provided prior to the contribution. Approximately $7.1 million of services provided by Diamondback are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2012. Approximately $40.4 million related to services performed by Diamondback are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2012.

As discussed in Note 3, Gulfport is the operator of its Niobrara Formation acreage under a development agreement with Windsor Niobrara. As operator, the Company is responsible for daily operations, monthly operation billings and monthly revenue disbursements for these properties. For the years ended December 31, 2013 and 2012, the Company billed Windsor Niobrara approximately $0.9 million and $7.5 million, respectively, for these services. At December 31, 2013, Windsor Niobrara owed the Company an immaterial amount for these services. At December 31, 2012, Windsor Niobrara owed the Company approximately $0.2 million for these services.

Windsor Ohio LLC ("Windsor Ohio") participated with the Company in the acquisition of certain leasehold interests in acreage located in the Utica Shale in Ohio. As operator of this acreage, the Company is responsible for daily operations, monthly operation billings and monthly revenue disbursements for these properties. For the years ended December 31, 2013 and 2012, the Company billed Windsor Ohio approximately $73.4 million and $163.7 million, respectively, for these services.

At December 31, 2013 and 2012, Windsor Ohio owed the Company approximately $1.6 million and $6.5 million, respectively, for these services. During the years ended December 31, 2013 and 2012, the Company purchased certain oil and natural gas properties in the Utica Shale from Windsor Ohio. For information regarding these transactions, see Note 2.

Rhino Exploration LLC ("Rhino") participated with the Company in the acquisition of certain leasehold interest in acreage located in the Utica Shale in Ohio. As operator of this acreage, the Company is responsible for daily operations, monthly operation billings and monthly revenue disbursements for these properties. For the year ended December 31, 2012, the Company billed Rhino approximately $4.4 million for these services. At December 31, 2012, Rhino owed the Company approximately $4.3 million for these services.

Stingray Pressure, which is 50% owned by the Company, provides well completion services as discussed above in Note 5. At December 31, 2013 and 2012, the Company owed Stingray Pressure approximately $8.3 million and $5.3 million, respectively, related to these services. Approximately $58.3 million and $4.3 million of services provided by Stingray Pressure are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2013 and 2012, respectively.

Stingray Cementing, which is 50% owned by the Company, provides well cementing services as discussed above in Note 5. At December 31, 2013, the Company owed Stingray Cementing approximately $1.5 million related to these services. No amounts were owed to Stingray Cementing at December 31, 2012. Approximately $4.0 million of services provided by Stingray Cementing are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2013.

Stingray Energy, which is 50% owned by the Company, provides rental tools for land-based oil and natural gas drilling, completion and workover activities as well as the transfer of fresh water to wellsites as discussed above in Note 5. At December 31, 2013, the Company owed Stingray Energy approximately $4.1 million related to these services. Approximately $5.1 million of services provided by Stingray Energy are included in oil and natural gas properties before elimination of intercompany profits on the accompanying consolidated balance sheets at December 31, 2013.

Athena Construction LLC (“Athena”) performs services for the Company at its WCBB and Hackberry fields. At December 31, 2013 and 2012, the Company owed Athena approximately $1.0 million and $1.5 million, respectively, related to these services. Approximately $0.6 million and $0.4 million of services provided by Athena are included in lease operating expenses in the consolidated statements of operations for the year ended December 31, 2013 and 2012, respectively. Approximately $4.1 million and $5.0 million related to services performed by Athena are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2013 and 2012, respectively.

Black Fin P&A, LLC (“Black Fin”) performs plugging and abandonment services for the Company at its WCBB field. No amounts were owed to Black Fin at December 31, 2013 and 2012. An immaterial amount of services performed by Black Fin are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2013. Approximately $0.7 million of services performed by Black Fin are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2012.

Panther Drilling Systems, LLC ("Panther") performs directional drilling services for the Company. At December 31, 2013 and 2012, the Company owed Panther approximately $1.8 million and an immaterial amount, respectively, related to these services. Approximately $12.6 million and an immaterial amount of services provided by Panther are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2013 and 2012, respectively.

Redback Directional Services, LLC ("Redback") provides coil tubing and flow back services for the Company. No amounts were owed to Redback at December 31, 2013. At 2012 the Company owed Redback $1.1 million related to these services. Approximately $0.1 million and $1.8 million related to services performed by Redback are included in oil and natural gas properties on the accompanying consolidated balance sheets at December 31, 2013 and 2012, respectively.

Caliber Development Company, LLC ("Caliber") provides building maintenance services for the Company's headquarters in Oklahoma City, Oklahoma. Caliber also leases office space to the Company. At December 31, 2013 and 2012, the Company owed Caliber an immaterial amount related to these services. Approximately $0.2 million and $0.1 million of services performed by Caliber and rent paid to Caliber are included in general and administrative expenses on the accompanying consolidated statements of operations for the year ended December 31, 2013 and 2012, respectively.

Each of Diamondback, Windsor Niobrara, Windsor Ohio, Rhino, Stingray Pressure, Stingray Cementing, Stingray Energy, Stingray Logistics, Athena, Black Fin, Panther, Redback and Caliber is affiliated with or controlled by Wexford. Prior to September 21, 2012, Wexford and/or its affiliates beneficially owned more than 10% of the Company's common stock and was deemed to be a related party. On or about September 28, 2012, Wexford's and/or its affiliates' ownership of Gulfport's common stock dropped to below 1% and, as a result, was no longer deemed to be a related party. Subsequent to September 28, 2012, the Company continued to treat Windsor Niobrara, Windsor Ohio, Athena, Black Fin, Panther, Redback and Caliber as related parties because Mr. Mike Liddell, the Company's former Chairman of the Board and a named executive officer during 2013, is the operating member of each such entity and also holds a 10% participation interest in Windsor Ohio and a 10% contingent participation interest in Windsor Niobrara, Athena, Black Fin, Panther, Redback and Caliber. During December 2012, Mr. Liddell had transferred his participation in Windsor Ohio to an entity he controlled. For the year ended December 31, 2012, the Company billed this entity directly in respect of his 10% interest in the amount of approximately $2.0 million. For the year ended December 31, 2012, the Company paid this entity approximately $0.1 million in respect of its interest in Windsor Ohio.

16. COMMITMENTS

Plugging and Abandonment Funds

In connection with the Company's acquisition in 1997 of the remaining 50% interest in its WCBB properties, the Company assumed the seller's (Chevron) obligation to contribute approximately $18,000 per month through March 2004 to a plugging and abandonment trust and the obligation to plug a minimum of 20 wells per year for 20 years commencing March 11, 1997. Chevron retained a security interest in production from these properties until abandonment obligations to Chevron have been fulfilled. Beginning in 2009, the Company could access the trust for use in plugging and abandonment charges associated with the property, although it has not yet done so. As of December 31, 2013, the plugging and abandonment trust totaled approximately $3.1 million. At December 31, 2013, the Company had plugged 354 wells at WCBB since it began its plugging program in 1997, which management believes fulfills its current minimum plugging obligation.

Contributions to 401(k) Plan

Gulfport sponsors a 401(k) and Profit Sharing plan under which eligible employees may contribute up to 100% of their total compensation up to the maximum pre-tax threshold through salary deferrals. Also under the plan, the Company will make a contribution each calendar year on behalf of each employee equal to at least 3% of his or her salary, regardless of the employee's participation in salary deferrals and may also make additional discretionary contributions. During the years ended December 31, 2013, 2012 and 2011, Gulfport incurred $0.6 million, $0.4 million, and $0.3 million, respectively, in contributions expense related to this plan.

Employment Agreements

Effective November 1, 2012, the Company entered into employment agreements with its executive officers, each with an initial three-year term that expires on November 1, 2015 subject to automatic one-year extensions unless terminated by either party to the agreement at least 90 days prior to the end of the then current term. These agreements provide for minimum salary and bonus levels which are subject to review and potential increase by the Compensation Committee and/or the Board of Directors, as well as participation in the Company's Amended and Restated 2005 Stock Incentive Plan (or other equity incentive plans that may be put in place for the benefit of employees) and other employee benefits. The aggregate minimum commitment for future salaries and bonuses at December 31, 2013 was approximately $3.5 million.

Gulfport's former Chairman, Mr. Liddell, resigned effective June 2013 at which date his employment agreement with Gulfport terminated. At that same date, the Company entered into a consulting agreement with Mr. Liddell. The minimum commitment under the consulting agreement at December 31, 2013 was approximately $1.1 million.

Firm Transportation Commitments

As of December 31, 2013, the Compay had approximately 183,000 MMBtu per day of firm sales contracted with third parties. Of these sales, 33,000 MMBtu per day, 100,000 MMBtu per day and 50,000 MMBtu per day expire in 2015, 2016 and 2017, respectively.

Operating Leases

The Company leases office facilities under non-cancellable operating leases exceeding one year. Future minimum lease commitments under these leases at December 31, 2013 are as follows:

	(In thousands)
2014	$ 536
2015	494
2016	426
2017	398
Total	$ 1,854

The following table presents rent expense for the years ended December 31, 2013, 2012 and 2011, respectively.

	For the years ended December 31,		
	2013	2012	2011
		(In thousands)	
Minimum rentals	$ 258	$ 139	$ 52
Less: Sublease rentals	45	7	—
	$ 213	$ 132	$ 52

17. CONTINGENCIES

The Louisiana Department of Revenue ("LDR") is disputing Gulfport's severance tax payments to the State of Louisiana from the sale of oil under fixed price contracts during the years 2005 through 2007. The LDR maintains that Gulfport paid approximately $1.8 million less in severance taxes under fixed price terms than the severance taxes Gulfport would have had to pay had it paid severance taxes on the oil at the contracted market rates only. Gulfport has denied any liability to the LDR for underpayment of severance taxes and has maintained that it was entitled to enter into the fixed price contracts with unrelated third parties and pay severance taxes based upon the proceeds received under those contracts. Gulfport has maintained its right to contest any final assessment or suit for collection if brought by the State. On April 20, 2009, the LDR filed a lawsuit in the 15th Judicial District Court, Lafayette Parish, in Louisiana against Gulfport seeking $2.3 million in severance taxes, plus interest and court costs. Gulfport filed a response denying any liability to the LDR for underpayment of severance taxes. The LDR had taken no further action on this lawsuit since filing its petition other than propounding discovery requests to which Gulfport has responded. Since serving discovery requests on the LDR and receiving the LDR's responses in 2012, there has been no further activity on the case and no trial date has been set.

In December 2010, the LDR filed two identical lawsuits against Gulfport in different venues (the 15th Judicial District Court and the 19th Judicial Court) to recover allegedly underpaid severance taxes on crude oil for the period January 1, 2007 through December 31, 2010, together with a claim for attorney's fees. The petitions do not make any specific claim for damages or unpaid taxes. As with the lawsuit filed by the LDR in 2009 discussed in the paragraph above, Gulfport denies all liability and will vigorously defend the lawsuit. The LDR filed motions to stay the lawsuits before Gulfport filed any responsive pleadings. After years of no activity on either of these lawsuits, the LDR recently moved to dismiss one of the identical lawsuits it filed in the 19th Judicial District Court in 2010, amended the petition it filed in the 15th Judicial District Court in 2010 and served discovery requests on Gulfport. The LDR asserts that Gulfport underpaid severance taxes by nearly $12 million from 2007 to 2010. The LDR also asserts that Gulfport owes an additional $4.4 million and may be subject to additional penalties. In 2013, the LDR asserted that Gulfport owes additional severance taxes in connection with the cash settlements it received to terminate forward sales contracts. The LDR's claims are still in their infancy and there has been no formal discovery. Gulfport maintains that the LDR's claims are not well-grounded in fact or law and intends to aggressively defend the lawsuits.

On July 30, 2010, six individuals and one limited liability company sued 15 oil and gas companies in Cameron Parish Louisiana for surface contamination in areas where the defendants operated in an action entitled Reeds et al. v. BP American

Production Company et al.,38th Judicial District. No. 10-18714. The plaintiffs' original petition for damages, which did not name Gulfport as a defendant, alleges that the plaintiffs' property located in Cameron Parish, Louisiana within the Hackberry oil field is contaminated as a result of historic oil and gas exploration and production activities. The plaintiffs allege that the defendants conducted, directed and participated in various oil and gas exploration and production activities on their property which allegedly have contaminated or otherwise caused damage to the property, and have sued the defendants for alleged breaches of oil, gas and mineral leases, as well as for alleged negligence, trespass, failure to warn, strict liability, punitive damages, lease liability, contract liability, unjust enrichment, restoration damages, assessment and response costs and stigma damages. On December 7, 2010, Gulfport was served with a copy of the plaintiffs' first supplemental and amending petition which added four additional plaintiffs and six additional defendants, including Gulfport, bringing the total number of defendants to 21. It also increased the total acreage at issue in this litigation from 240 acres to approximately 1,700 acres. In addition to the damages sought in the original petition, the plaintiffs now also seek: damages sufficient to cover the cost of conducting a comprehensive environmental assessment of all present and yet unidentified pollution and contamination of their property; the cost to restore the property to its pre-polluted original condition; damages for mental anguish and annoyance, discomfort and inconvenience caused by the nuisance created by defendants; land loss and subsidence damages and the cost of backfilling canals and other excavations; damages for loss of use of land and lost profits and income; attorney fees and expenses and damages for evaluation and remediation of any contamination that threatens groundwater. In addition to Gulfport, current defendants include ExxonMobil Oil Corporation, Mobil Exploration & Producing North America Inc., Chevron U.S.A. Inc., The Superior Oil Company, Union Oil Company of California, BP America Production Company, Tempest Oil Company, Inc., ConocoPhillips Company, Continental Oil Company, WM. T. Burton Industries, Inc., Freeport Sulphur Company, Eagle Petroleum Company, U.S. Oil of Louisiana, M&S Oil Company, and Empire Land Corporation, Inc. of Delaware. On January 21, 2011, Gulfport filed a pleading challenging the legal sufficiency of the petitions on several grounds and requesting that they either be dismissed or that plaintiffs be required to amend such petitions. In response to the pleadings filed by Gulfport and similar pleadings filed by other defendants, the plaintiffs filed a third amending petition with exhibits which expands the description of the property at issue, attaches numerous aerial photos and identifies the mineral leases at issue. In response, Gulfport and numerous defendants re-urged their pleadings challenging the legal sufficiency of the petitions. Some of the defendants' grounds for challenging the plaintiffs' petitions were heard by the court on May 25, 2011 and were denied. The court signed the written judgment on December 9, 2011. Gulfport noticed its intent to seek supervisory review on December 19, 2011 and the trial court fixed a return date of January 11, 2012 for the filing of the writ application. Gulfport filed its supervisory writ, which was denied by the Louisiana Third Circuit Court of Appeal and the Louisiana Supreme Court. The parties engaged in a non-binding mediation in July 2013 and discussion are on-going. At this time, the parties are continuing to conduct discovery. The trial date has been continued to July 2014.

Due to the early stages of the LDR and Reed litigation, the outcome is uncertain and management cannot determine the amount of loss, if any, that may result. In each case, management has determined the possibility of loss is remote. However, litigation is inherently uncertain. Adverse decisions in one or more of the above matters could have a material adverse effect on the Company's financial condition or results of operations and management cannot determine the amount of loss, if any, that may result.

The Company has been named as a defendant in various other lawsuits related to its business. In each such case, management has determined that the possibility of loss is remote. The resolution of these matters is not expected to have a material adverse effect on the Company's financial condition or results of operations in future periods.

Concentration of Credit Risk

Gulfport operates in the oil and gas industry principally in the state of Louisiana with sales to refineries, re-sellers such as pipeline companies, and local distribution companies. While certain of these customers are affected by periodic downturns in the economy in general or in their specific segment of the oil and gas industry, Gulfport believes that its level of credit-related losses due to such economic fluctuations has been immaterial and will continue to be immaterial to the Company's results of operations in the long term.

The Company maintains cash balances at several banks. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. At December 31, 2013, Gulfport held cash in excess of insured limits in these banks totaling $457.7 million.

During the year ended December 31, 2013, Gulfport sold approximately 99% of its oil production to Shell Trading Company ("Shell"), 100% of its natural gas liquids production to Markwest Utica and 32%, 31% and 17% of its natural gas production to Sequent Energy Management, L.P., Hess and Interstate Gas Supply, Inc., respectively. During the year ended December 31, 2012, Gulfport sold approximately 92% and 8% of its oil production to Shell and Diamondback O&G, respectively, 91% of its natural gas liquids production to Diamondback O&G, and 41%, 18% and 16% of its natural gas production to Noble Americas Gas, Hess and Chevron, respectively. During the year ended December 31, 2011, Gulfport sold approximately 93% and 7% of its oil production to Shell and Diamondback O&G, respectively, 100% of its natural gas liquids production to Diamondback O&G and 50%, 27%, and 22% of its natural gas production to Hilcorp Energy Company, Chevron, and Diamondback O&G, respectively.

18. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On October 17, 2012 and December 21, 2012, the Company issued an aggregate of $300.0 million of its 7.75% Senior Notes (the "Notes"). The Notes are guaranteed on a senior unsecured basis by all existing consolidated subsidiaries that guarantee the Company's secured revolving credit facility or certain other debt (the "Guarantors"). The Notes are not guaranteed by Grizzly Holdings, Inc., (the "Non-Guarantor"). The Guarantors are 100% owned by Gulfport (the "Parent"), and the guarantees are full, unconditional, joint and several. There are no significant restrictions on the ability of the Parent or the Guarantors to obtain funds from each other in the form of a dividend or loan.

The following condensed consolidating balance sheets, statements of operations, statements of comprehensive income (loss) and statements of cash flows are provided for the Parent, the Guarantors and the Non-Guarantor and include the consolidating adjustments and eliminations necessary to arrive at the information for the Company on a condensed consolidated basis. The information has been presented using the equity method of accounting for the Parent's ownership of the Guarantors and the Non-Guarantor.

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 451,431	$ 7,525	$ —	$ —	$ 458,956
Accounts receivable - oil and gas	58,662	162	—	—	58,824
Accounts receivable - related parties	2,617	—	—	—	2,617
Accounts receivable - intercompany	21,379	27	—	(21,406)	—
Prepaid expenses and other current assets	2,581	—	—	—	2,581
Deferred tax asset	6,927	—	—	—	6,927
Short-term derivative instruments	324	—	—	—	324
Note receivable - related party	875	—	—	—	875
Total current assets	544,796	7,714	—	(21,406)	531,104
Property and equipment:					
Oil and natural gas properties, full-cost accounting	2,470,411	7,340	—	(573)	2,477,178
Other property and equipment	11,102	29	—	—	11,131
Accumulated depletion, depreciation, amortization and impairment	(784,695)	(22)	—	—	(784,717)
Property and equipment, net	1,696,818	7,347	—	(573)	1,703,592
Other assets:					
Equity investments and investments in subsidiaries	432,727	—	191,473	(184,132)	440,068
Derivative instruments	521	—	—	—	521
Other assets	17,851	—	—	—	17,851
Total other assets	451,099	—	191,473	(184,132)	458,440
Total assets	$ 2,692,713	$ 15,061	$ 191,473	$ (206,111)	$ 2,693,136
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 190,284	$ 423	$ —	$ —	$ 190,707
Accounts payable - intercompany	—	21,296	110	(21,406)	—
Asset retirement obligation - current	795	—	—	—	795
Short-term derivative instruments	12,280	—	—	—	12,280
Current maturities of long-term debt	159	—	—	—	159
Total current liabilities	203,518	21,719	110	(21,406)	203,941
Long-term derivative instrument	11,366	—	—	—	11,366
Asset retirement obligation - long-term	14,288	—	—	—	14,288
Deferred tax liability	114,275	—	—	—	114,275
Long-term debt, net of current maturities	299,028	—	—	—	299,028
Total liabilities	642,475	21,719	110	(21,406)	642,898
Stockholders' equity:					
Common stock	851	—	—	—	851
Paid-in capital	1,813,058	322	208,277	(208,599)	1,813,058
Accumulated other comprehensive income (loss)	(9,781)	—	(9,781)	9,781	(9,781)
Retained earnings (accumulated deficit)	246,110	(6,980)	(7,133)	14,113	246,110
Total stockholders' equity	2,050,238	(6,658)	191,363	(184,705)	2,050,238
Total liabilities and stockholders' equity	$ 2,692,713	$ 15,061	$ 191,473	$ (206,111)	$ 2,693,136

CONDENSED CONSOLIDATING BALANCE SHEETS
(Amounts in thousands)

	December 31, 2012				
	Parent	**Guarantors**	**Non-Guarantor**	**Eliminations**	**Consolidated**
Assets					
Current assets:					
Cash and cash equivalents	$ 165,293	$ 1,795	$ —	$ —	$ 167,088
Accounts receivable - oil and gas	25,070	545	—	—	25,615
Accounts receivable - related parties	33,806	1,042	—	—	34,848
Accounts receivable - intercompany	15,368			(15,368)	—
Prepaid expenses and other current assets	1,506	—	—	—	1,506
Short-term derivative instruments	664	—	—	—	664
Total current assets	241,707	3,382	—	(15,368)	229,721
Property and equipment:					
Oil and natural gas properties, full-cost accounting,	1,606,172	4,918	—	—	1,611,090
Other property and equipment	8,642	20	—	—	8,662
Accumulated depletion, depreciation, amortization and impairment	(665,864)	(20)	—	—	(665,884)
Property and equipment, net	948,950	4,918	—	—	953,868
Other assets:					
Equity investments and investments in subsidiaries	374,209	—	172,766	(165,491)	381,484
Other assets	13,295	—	—	—	13,295
Total other assets	387,504	—	172,766	(165,491)	394,779
Total assets	$ 1,578,161	$ 8,300	$ 172,766	$ (180,859)	$ 1,578,368
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable and accrued liabilities	$ 110,037	$ 207	$ —	$ —	$ 110,244
Accounts payable - intercompany	—	15,259	109	(15,368)	—
Asset retirement obligation - current	60	—	—	—	60
Short-term derivative instruments	10,442	—	—	—	10,442
Current maturities of long-term debt	150	—	—	—	150
Total current liabilities	120,689	15,466	109	(15,368)	120,896
Asset retirement obligation - long-term	13,215	—	—	—	13,215
Deferred tax liability	18,607	—	—	—	18,607
Long-term debt, net of current maturities	298,888	—	—	—	298,888
Other non-current liabilities	354	—	—	—	354
Total liabilities	451,753	15,466	109	(15,368)	451,960
Stockholders' equity:					
Common stock	674	—	—	—	674
Paid-in capital	1,036,245	322	174,348	(174,670)	1,036,245
Accumulated other comprehensive income (loss)	(3,429)	—	2,442	(2,442)	(3,429)
Retained earnings (accumulated deficit)	92,918	(7,488)	(4,133)	11,621	92,918
Total stockholders' equity	1,126,408	(7,166)	172,657	(165,491)	1,126,408
Total liabilities and stockholders' equity	$ 1,578,161	$ 8,300	$ 172,766	$ (180,859)	$ 1,578,368

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2013				
	Parent	**Guarantors**	**Non-Guarantor**	**Eliminations**	**Consolidated**
Total revenues	$ 261,809	$ 1,517	$ —	$ (573)	$ 262,753
Costs and expenses:					
Lease operating expenses	25,971	732	—	—	26,703
Production taxes	26,848	85	—	—	26,933
Midstream transportation, processing and marketing	10,999	31	—	—	11,030
Depreciation, depletion, and amortization	118,878	2	—	—	118,880
General and administrative	22,359	159	1	—	22,519
Accretion expense	717	—	—	—	717
Loss on sale of assets	508	—	—	—	508
	206,280	1,009	1	—	207,290
INCOME (LOSS) FROM OPERATIONS	55,529	508	(1)	(573)	55,463
OTHER (INCOME) EXPENSE:					
Interest expense	17,490	—	—	—	17,490
Interest income	(297)	—	—	—	(297)
(Income) loss from equity method investments and investments in subsidiaries	(212,992)	—	2,999	(3,065)	(213,058)
	(195,799)	—	2,999	(3,065)	(195,865)
INCOME (LOSS) BEFORE INCOME TAXES	251,328	508	(3,000)	2,492	251,328
INCOME TAX EXPENSE	98,136	—	—	—	98,136
NET INCOME (LOSS)	$ 153,192	$ 508	$ (3,000)	$ 2,492	$ 153,192

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 247,637	$ 1,289	$ —	$ —	$ 248,926
Costs and expenses:					
Lease operating expenses	23,644	664	—	—	24,308
Production taxes	28,874	83	—	—	28,957
Midstream transportation, processing and marketing	432	11			443
Depreciation, depletion, and amortization	90,749	—	—	—	90,749
General and administrative	13,602	132	74	—	13,808
Accretion expense	698	—	—	—	698
Gain on sale of assets	(7,300)	—	—	—	(7,300)
	150,699	890	74	—	151,663
INCOME (LOSS) FROM OPERATIONS	96,938	399	(74)	—	97,263
OTHER (INCOME) EXPENSE:					
Interest expense	7,458	—	—	—	7,458
Interest income	(72)	—	—	—	(72)
(Income) loss from equity method investments and investments in subsidiaries	(5,182)	—	1,512	(4,652)	(8,322)
	2,204	—	1,512	(4,652)	(936)
INCOME (LOSS) FROM COTINUING OPERATIONS BEFORE INCOME TAXES	94,734	399	(1,586)	4,652	98,199
INCOME TAX EXPENSE	26,363	—	—	—	26,363
INCOME (LOSS) FROM CONTINUING OPERATIONS	68,371	399	(1,586)	4,652	71,836
DISCONTINUED OPERATIONS					
Loss on disposal of Belize properties, net of tax	—	3,465	—	—	3,465
NET INCOME (LOSS)	$ 68,371	$ (3,066)	$ (1,586)	$ 4,652	$ 68,371

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS
(Amounts in thousands)

	Year Ended December 31, 2011				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Total revenues	$ 228,281	$ 973	$ —	$ —	$ 229,254
Costs and expenses:					
Lease operating expenses	20,168	729	—	—	20,897
Production taxes	25,991	63	—	—	26,054
Midstream transportation, processing and marketing	275	4	—	—	279
Depreciation, depletion, and amortization	62,320	—	—	—	62,320
General and administrative	8,038	11	25	—	8,074
Accretion expense	666	—	—	—	666
	117,458	807	25	—	118,290
INCOME (LOSS) FROM OPERATIONS	110,823	166	(25)	—	110,964
OTHER (INCOME) EXPENSE:					
Interest expense	1,400	—	—	—	1,400
Interest income	(39)	—	(147)	—	(186)
(Income) loss from equity method investments and investments in subsidiaries	1,130	—	1,592	(1,304)	1,418
	2,491	—	1,445	(1,304)	2,632
INCOME (LOSS) BEFORE INCOME TAXES	108,332	166	(1,470)	1,304	108,332
INCOME TAX BENEFIT	(90)	—	—	—	(90)
NET INCOME (LOSS)	$ 108,422	$ 166	$ (1,470)	$ 1,304	$ 108,422

CONDENSED CONSOLIDATING STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Amounts in thousands)

	Year Ended December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 153,192	$ 508	$ (3,000)	$ 2,492	$ 153,192
Foreign currency translation adjustment	(12,223)	—	(12,223)	12,223	(12,223)
Change in fair value of derivative instruments, net of taxes	(4,419)	—	—	—	(4,419)
Reclassification of settled contracts, net of taxes	10,290	—	—	—	10,290
Other comprehensive income (loss)	(6,352)	—	(12,223)	12,223	(6,352)
Comprehensive income	$ 146,840	$ 508	$ (15,223)	$ 14,715	$ 146,840

	Year Ended December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 68,371	$ (3,066)	$ (1,586)	$ 4,652	$ 68,371
Foreign currency translation adjustment	1,355	—	1,355	(1,355)	1,355
Change in fair value of derivative instruments, net of taxes	(8,452)	—	—	—	(8,452)
Reclassification of settled contracts, net of taxes	1,005	—	—	—	1,005
Other comprehensive income (loss)	(6,092)	—	1,355	(1,355)	(6,092)
Comprehensive income	$ 62,279	$ (3,066)	$ (231)	$ 3,297	$ 62,279

	Year Ended December 31, 2011				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net income (loss)	$ 108,422	$ 166	$ (1,470)	$ 1,304	$ 108,422
Foreign currency translation adjustment	(1,865)	—	(1,865)	1,865	(1,865)
Change in fair value of derivative instruments, net of taxes	1,576	—	—	—	1,576
Reclassification of settled contracts, net of taxes	4,720	—	—	—	4,720
Other comprehensive income (loss)	4,431	—	(1,865)	1,865	4,431
Comprehensive income	$ 112,853	$ 166	$ (3,335)	$ 3,169	$ 112,853

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS
(Amounts in thousands)

	Year Ended December 31, 2013				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 182,961	$ 8,104	$ —	$ —	$ 191,065
Net cash provided by (used in) investing activities	(661,886)	(2,374)	(33,929)	33,929	(664,260)
Net cash provided by (used in) financing activities	765,063	—	33,929	(33,929)	765,063
Net increase in cash and cash equivalents	286,138	5,730	—	—	291,868
Cash and cash equivalents at beginning of period	165,293	1,795	—	—	167,088
Cash and cash equivalents at end of period	$ 451,431	$ 7,525	$ —	$ —	$ 458,956

	Year Ended December 31, 2012				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ 195,734	$ 3,425	$ (1)	$ —	$ 199,158
Net cash provided by (used in) investing activities	(838,177)	(2,402)	(103,915)	103,915	(840,579)
Net cash provided by (used in) financing activities	714,612	—	103,915	(103,915)	714,612
Net increase (decrease) in cash and cash equivalents	72,169	1,023	(1)	—	73,191
Cash and cash equivalents at beginning of period	93,124	772	1	—	93,897
Cash and cash equivalents at end of period	$ 165,293	$ 1,795	$ —	$ —	$ 167,088

	Year Ended December 31, 2011				
	Parent	Guarantors	Non-Guarantor	Eliminations	Consolidated
Net cash provided by operating activities	$ 154,329	$ 3,808	$ 1	$ —	$ 158,138
Net cash provided by (used in) investing activities	(320,203)	(3,045)	(25,858)	25,858	(323,248)
Net cash provided by (used in) financing activities	256,539	—	25,858	(25,858)	256,539
Net increase in cash and cash equivalents	90,665	763	1	—	91,429
Cash and cash equivalents at beginning of period	2,459	9	—	—	2,468
Cash and cash equivalents at end of period	$ 93,124	$ 772	$ 1	$ —	$ 93,897

19. SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES (UNAUDITED)

As discussed above in Notes 4 and 5, the Company owned a 7.2% equity interest in Diamondback at December 31, 2013 which interest is shown below. At December 31, 2012, the Company owned a 21.4% equity interest in Diamondback. The Company did not own an equity interest in Diamondback at December 31, 2011.

The following is historical revenue and cost information relating to the Company's oil and gas operations located entirely in the United States:

Capitalized Costs Related to Oil and Gas Producing Activities

	2013	2012
	(In thousands)	
Proven properties	$ 1,526,588	$ 984,795
Unproven properties	950,590	626,295
	2,477,178	1,611,090
Accumulated depreciation, depletion, amortization and impairment reserve	(779,561)	(661,442)
Net capitalized costs	$ 1,697,617	$ 949,648
Equity investment in Diamondback Energy, Inc.		
Proven properties	$ 92,074	$ 123,370
Unproven properties	26,608	25,947
	118,682	149,317
Accumulated depreciation, depletion, amortization and impairment reserve	$ (15,180)	$ (31,052)
Net capitalized costs	$ 103,502	$ 118,265

Costs Incurred in Oil and Gas Property Acquisition and Development Activities

	2013	2012	2011
		(In thousands)	
Acquisition	$ 338,153	$ 513,904	$ 119,522
Development of proved undeveloped properties	408,121	121,787	123,489
Exploratory	26,174	93,397	3,994
Recompletions	44,633	24,643	17,259
Capitalized asset retirement obligation	3,556	2,195	1,390
Total	$ 820,637	$ 755,926	$ 265,654
Equity investment in Diamondback Energy, Inc.			
Acquisition	$ 44,534	$ 49,895	$ —
Development of proved undeveloped properties	6,369	22,740	—
Exploratory	17,491	3,755	—
Capitalized asset retirement obligation	50	203	—
Total	$ 68,444	$ 76,593	$ —

Results of Operations for Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and gas. The income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion and amortization allowances, after giving effect to the permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas production.

	2013	2012	2011
		(In thousands)	
Revenues	$ 262,225	$ 248,601	$ 228,953
Production costs	(64,666)	(53,708)	(47,230)
Depletion	(118,118)	(90,230)	(61,965)
	79,441	104,663	119,758
Income tax expense (benefit)			
Current	—	730	282
Deferred	49,447	25,633	(372)
	49,447	26,363	(90)
Results of operations from producing activities	$ 29,994	$ 78,300	$ 119,848
Depletion per barrel of oil equivalent (BOE)	$ 28.68	$ 35.07	$ 26.56

Results of Operations from equity method investment in Diamondback Energy, Inc.			
Revenues	$ 14,976	$ 16,042	$ —
Production costs	(2,518)	(4,474)	—
Depletion	(4,754)	(5,515)	—
	7,704	6,053	—
Income tax expense (benefit)	2,286	2,158	—
Results of operations from producing activities	$ 5,418	$ 3,895	$ —

Oil and Gas Reserves

The following table presents estimated volumes of proved developed and undeveloped oil and gas reserves as of December 31, 2013, 2012 and 2011 and changes in proved reserves during the last three years. The reserve reports use an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month period ended December 31, 2013, 2012 and 2011, in accordance with guidelines of the SEC applicable to reserves estimates. Volumes for oil are stated in thousands of barrels (MBbls) and volumes for gas are stated in millions of cubic feet (MMcf). The prices used for the 2013 reserve report are $96.78 per barrel of oil, $3.67 per MMbtu and $41.23 per barrel for NGLs, adjusted by lease for transportation fees and regional price differentials, and for oil and gas reserves, respectively. The prices used at December 31, 2012 and 2011 for reserve report purposes are $91.32 per barrel and $2.76 per MMbtu and $96.19 per barrel and $4.12 per MMbtu, respectively.

Gulfport emphasizes that the volumes of reserves shown below are estimates which, by their nature, are subject to revision. The estimates are made using all available geological and reservoir data, as well as production performance data. These estimates are reviewed annually and revised, either upward or downward, as warranted by additional performance data.

	2013			2012			2011		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	(MBbls)	(MMcf)	(MBbls)	(MBbls)	(MMcf)	(MBbls)	(MBbls)	(MMcf)	(MBbls)
Proved Reserves									
Beginning of the period	8,106	33,771	145	13,954	15,728	2,791	16,597	16,158	3,107
Purchases in oil and gas reserves in place	—	—	—	—	—	—	2	19	—
Extensions and discoveries	2,765	123,597	5,850	4,732	31,265	148	3,723	2,091	217
Sales of oil and gas reserves in place	—	—	—	(7,875)	(11,757)	(2,729)	—	—	—
Revisions of prior reserve estimates	(208)	(2,031)	—	(382)	(357)	—	(4,240)	(1,662)	(474)
Current production	(2,317)	(8,891)	(320)	(2,323)	(1,108)	(65)	(2,128)	(878)	(59)
End of period	8,346	146,446	5,675	8,106	33,771	145	13,954	15,728	2,791
Proved developed reserves	5,609	94,552	3,527	5,175	18,482	44	6,780	6,152	705
Proved undeveloped reserves	2,737	51,894	2,148	2,931	15,289	101	7,174	9,576	2,086
Equity investment in Diamondback Energy, Inc.									
Proved Reserves									
Beginning of the period	5,606	7,398	1,766	3,874	4,398	1,080	—	—	—
Change in ownership interest in Diamondback	(3,720)	(4,909)	(1,171)	—	—	—	—	—	—
Purchases in oil and gas reserves in place	528	752	120	1,543	2,292	540	—	—	—
Extensions and discoveries	1,227	1,741	331	665	804	186	—	—	—
Revisions of prior reserve estimates	(428)	(417)	(249)	(314)	82	(1)	—	—	—
Current production	(146)	(124)	(26)	(162)	(178)	(39)	—	—	—
End of period	3,067	4,441	771	5,606	7,398	1,766	—	—	—
Proved developed reserves	1,425	2,263	358	1,539	2,753	641	—	—	—
Proved undeveloped reserves	1,642	2,178	413	4,068	4,645	1,124	—	—	—

In 2013, the Company experienced extensions and discoveries of 27,805 thousand barrels of oil equivalent (MBOE) of proved reserves attributable to the development of the Company's Utica Shale acreage. The Company contributed its Permian Basin assets to Diamondback in 2012, as discussed in Note 4, resulting in a decrease of 12,564 MBOE in estimated proved reserves in 2012. The Company experienced extensions and discoveries of proved reserves of 6,675 MBOE in 2012 attributable to the discovery and development of the Company's Utica Shale acreage. In addition, the Company experienced downward reserve revisions of 442 MBOE in estimated proved reserves in 2012 primarily due to a change in the drilling schedule of its Niobrara acreage. The Company also experienced downward reserve revisions in 2011. These downward revisions were primarily the result of the drilling of PUDs during the Company’s 2011 drilling program and ethane takeaway issues in the Permian Basin.

Discounted Future Net Cash Flows

The following tables present the estimated future cash flows, and changes therein, from Gulfport’s proven oil and gas reserves as of December 31, 2013, 2012 and 2011 using an unweighted average first-of-the-month price for the period January through December 31, 2013, 2012 and 2011.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Future cash flows	$ 1,657,708	$ 954,833	$ 1,594,050
Future development and abandonment costs	(272,500)	(159,113)	(306,810)
Future production costs	(274,428)	(147,024)	(295,383)
Future production taxes	(78,647)	(89,175)	(124,739)
Future income taxes	(172,691)	(114,867)	(229,649)
Future net cash flows	859,442	444,654	637,469
10% discount to reflect timing of cash flows	(280,976)	(96,013)	(260,788)
Standardized measure of discounted future net cash flows	$ 578,466	$ 348,641	$ 376,681
Equity investment in Diamondback Energy, Inc. Standardized measure of discounted cash flows			
Future cash flows	$ 331,505	$ 592,669	$ —
Future development and abandonment costs	(37,229)	(115,869)	—
Future production costs	(58,096)	(165,553)	—
Future production taxes	(22,925)	(30,122)	—
Future income taxes	(48,547)	(71,669)	—
Future net cash flows	164,708	209,456	—
10% discount to reflect timing of cash flows	(94,462)	(130,871)	—
Standardized measure of discounted future net cash flows	$ 70,246	$ 78,585	$ —

In order to develop its proved undeveloped reserves according to the drilling schedule used by the engineers in Gulfport's reserve report, the Company will need to spend $135.4 million, $68.7 million and $8.5 million during years 2014, 2015 and 2016, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Sales and transfers of oil and gas produced, net of production costs	$ (197,559)	$ (194,893)	$ (181,723)
Net changes in prices, production costs, and development costs	65,573	108,941	136,071
Acquisition of oil and gas reserves in place	—	—	72
Extensions and discoveries	130,826	151,654	107,110
Previously estimated development costs incurred during the period	43,478	10,211	41,193
Revisions of previous quantity estimates, less related production costs	(3,591)	(10,504)	(112,553)
Sales of reserves in place	—	(214,867)	—
Accretion of discount	34,864	37,668	31,549
Net changes in income taxes	(30,239)	25,585	(36,674)
Change in production rates and other	186,473	58,165	76,149
Total change in standardized measure of discounted future net cash flows	$ 229,825	$ (28,040)	$ 61,194
Equity investment in Diamondback Energy, Inc. Changes in standardized measure of discounted cash flows			
Change in ownership interest in Diamondback	$ (52,145)	$ —	$ —
Sales and transfers of oil and gas produced, net of production costs	(12,524)	(11,601)	—
Net changes in prices, production costs, and development costs	3,312	(14,596)	—
Acquisition of oil and gas reserves in place	21,968	23,090	—
Extensions and discoveries	39,776	16,969	—
Previously estimated development costs incurred during the period	5,517	19,014	—
Revisions of previous quantity estimates, less related production costs	(9,143)	(4,897)	—
Accretion of discount	4,175	7,803	—
Net changes in income taxes	(12,137)	(26,866)	—
Change in production rates and other	2,862	(8,358)	—
Total change in standardized measure of discounted future net cash flows	$ (8,339)	$ 558	$ —

20. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table summarizes quarterly financial data for the years ended December 31, 2013 and 2012:

	2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 55,000	$ 70,434	$ 69,252	$ 68,067
Income from operations	14,944	22,456	15,137	2,926
Income tax expense	28,195	25,514	23,400	21,027
Net income	44,559	43,828	40,527	24,278
Income per share:				
Basic	$ 0.61	$ 0.57	$ 0.52	$ 0.30
Diluted	$ 0.61	$ 0.56	$ 0.52	$ 0.30

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$ 65,461	$ 66,325	$ 60,537	$ 56,603
Income from operations	27,263	25,947	18,178	25,875
Income tax expense (benefit)	—	—	15,514	10,849
Net income	26,869	25,117	502	15,883
Income per share:				
Basic	$ 0.48	$ 0.45	$ 0.01	$ 0.28
Diluted	$ 0.48	$ 0.45	$ 0.01	$ 0.28

21. SUBSEQUENT EVENTS

In January 2014, the Company entered into fixed price swaps for 25,000 MMBtu of natural gas per day at a weighted average price of $4.20 per MMBtu for the period from May 2014 through December 2015. For the period from June 2014 through December 2015, the Company entered into fixed price swaps for 25,000 MMBtu of natural gas per day at a weighted average price of $4.21 per MMBtu. The Company's fixed price swap contracts are tied to the commodity prices on NYMEX. The Company will receive the fixed price amount stated in the contract and pay to its counterparty the current market price as listed on NYMEX for natural gas.

On February 26, 2014, the Company entered into a binding letter of intent with Rhino Resources Partners LP ("Rhino") to acquire approximately 8,200 additional net acres in the Utica Shale of Eastern Ohio and approximately 1,000 BOEPD of production during January 2014 for a total purchase price of $185.0 million, subject to closing adjustments. These assets constitute all the rights, title and interest in leasehold and mineral interests covered by all oil and gas leases owned by Rhino in the Utica Shale in Eastern Ohio, together with all wells, production, data, equipment, contracts permits and privileges relating to the ownership of such properties. Gulfport is the operator of substantially all of this acreage. The Company plans to fund this acreage acquisition from existing cash on hand. The acquisition is expected to close by the end of March 2014, however the transaction remains subject to completion of due diligence and other closing conditions, and there can be no assurance that the transaction will be completed.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Contribution Agreement, dated May 7, 2012, by and between the Company and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on May 8, 2012).
2.2	Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 18, 2012).
2.3	Amendment, dated December 19, 2012, to the Purchase and Sale Agreement, dated December 17, 2012, by and between Windsor Ohio LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 20, 2012).
2.4	Purchase and Sale Agreement, dated February 11, 2013, by and between Windsor Ohio, LLC, as seller, and Gulfport Energy Corporation, as purchaser (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 15, 2013).
3.1	Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
3.2	Certificate of Amendment No. 1 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.2 to Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 6, 2009).
3.3	Certificate of Amendment No. 2 to Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 12, 2006).
3.5	First Amendment to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on July 23, 2013).
4.1	Form of Common Stock certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 2 to the Registration Statement on Form SB-2, File No. 333-115396, filed by the Company with the SEC on July 22, 2004).
4.2	Registration Rights Agreement, dated as of February 23, 2005, by and among the Company, Southpoint Fund LP, a Delaware limited partnership, Southpoint Qualified Fund LP, a Delaware limited partnership and Southpoint Offshore Operating Fund, LP, a Cayman Islands exempted limited partnership (incorporated by reference to Exhibit 10.7 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2005).
4.3	Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.3 of Form 10-QSB, File No. 000-19514, filed by the Company with the SEC on November 11, 2005).
4.4	Amendment No. 1, dated February 14, 2006, to the Registration Rights Agreement, dated as of March 29, 2002, by and among Gulfport Energy Corporation, Gulfport Funding LLC, certain other affiliates of Wexford and the other Investors Party thereto (incorporated by reference to Exhibit 10.15 of Form 10-KSB, File No. 000-19514, filed by the Company with the SEC on March 31, 2006).
4.5	Indenture, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Gulfport Energy Corporation's 7.750% Senior Note Due November 1, 2020) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.6	Registration Rights Agreement, dated as of October 17, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 23, 2012).
4.7	First Supplemental Indenture, dated December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).

4.8	Registration Rights Agreement, dated as of December 21, 2012, among Gulfport Energy Corporation, subsidiary guarantors party thereto and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on December 26, 2012).
10.1+	2013 Restated Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form S-4, File No. 333-189992, filed by the Company with the SEC on July 17, 2013).
10.2+	Form of Stock Option Agreement (incorporated by reference to Exhibit 10.2 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on April 26, 2006).
10.3+*	Form of Restricted Stock Award Agreement.
10.4+	Consulting Agreement, effective as of June 14, 2013, by and between the Company and Mike Liddell (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on June 19, 2013).
10.5+	Separation and Release Agreement, dated as of January 31, 2014, by and between the Company and James D. Palm (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 4, 2014).
10.6+	Employment Agreement, dated November 7, 2012, between the Company and Michael G. Moore (incorporated by reference to Exhibit 10.6 to the Form 10-Q, File No. 000-19514, filed by the Company with the SEC on November 8, 2012).
10.7	Amended and Restated Credit Agreement, dated as of December 27, 2013, by and among the Company, as borrower, The Bank of Nova Scotia, as administrative agent, sole lead arranger and sole bookrunner, Amegy Bank National Association, as syndication agent, KeyBank National Association, as documentation agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Form 8-K, File No. 000-19514, filed by the Company with the SEC on January 3, 2014).
10.8	Investor Rights Agreement, dated as of October 11, 2012, between Gulfport Energy Corporation and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 000-19514, filed by the Company with the SEC on October 17, 2012).
14	Code of Ethics (incorporated by reference to Exhibit 14 of Form 8-K, File No. 000-19514, filed by the Company with the SEC on February 14, 2006).
21*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company.
23.4*	Consent of Grant Thornton LLP with respect to financial statements of Diamondback Energy, Inc.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Report of Netherland, Sewell & Associates, Inc.
99.2*	Report of Ryder Scott Company.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.

101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** Furnished herewith, not filed.

+ Management contract, compensatory plan or arrangement.

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CORPORATE INFORMATION

DIRECTORS

David L. Houston, Chairman of the Board
Principal | Houston & Associates

Craig Groeschel, Independent Director
Senior Pastor & Founder | LifeChurch.tv

Donald Dillingham, Independent Director
Senior Portfolio Manager |
Avondale Investments & Merit Advisors

Michael G. Moore, Director
Chief Executive Officer & President |
Gulfport Energy

Michael S. Reddin, Independent Director
Chairman, President & Chief Executive Officer |
Davis Petroleum

Scott Streller, Independent Director
Principal & Founder | Streller Insurance &
Financial Services

MANAGEMENT

Michael G. Moore | Chief Executive Officer
& President

Ross Kirtley | Chief Operating Officer

Keri Crowell | Vice President & Controller

Lester Zitkus | Vice President, Land

Mark Malone | Vice President, Operations

Paul Heerwagen | Vice President,
Corporate Development

Rob Jones | Vice President, Drilling

Steve Baldwin | Vice President,
Reservoir Engineering

Stuart Maier | Vice President, Geosciences

Randy Wilson | Geologist & Geophysicist

Ty Peck | Managing Director,
Midstream Operations

ANNUAL MEETING

The annual meeting of shareholders is scheduled to be held at:
10:00 a.m., Thursday, June 12th, 2014

The meeting will be held at the company headquarters at:
14313 North May Avenue, Suite 100
Oklahoma City, OK 73134

TRANSFER AGENT

For information regarding change of address, lost certificates or similar inquiries, please contact our transfer agent:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021

Toll free number for Shareholders:
800-962-4284

Outside the U.S. and Canada:
781-575-3120

MARKET INFORMATION

Gulfport Energy's common stock is traded on the NASDAQ Global Select Market under the symbol GPOR.

INVESTOR RELATIONS

For additional information concerning Gulfport Energy's operational and financial results, investors and analysts, please contact Gulfport Investor Relations at 405-242-4888.

MORE INFORMATION

Additional company information, such as company presentations, press releases and other material can be found on the company website at:
www.gulfportenergy.com

CROXSON Design www.croxsondesign.com

GULFPORT ENERGY CORPORATION
14313 North May Avenue, Suite 100
Oklahoma City, OK 73134
(405) 848-8807

www.gulfportenergy.com