Matador Resources Co
Form 10-K
March 18, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2012

or

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 001-34574

Matador Resources Company

(Exact name of registrant as specified in its charter)

Texas	**27-4662601**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
5400 LBJ Freeway, Suite 1500 Dallas, Texas 75240	**75240**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (972) 371-5200

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	New York Stock Exchange

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant s most recently completed second fiscal quarter was $454,393,967.

As of March 14, 2013, there were 55,894,438 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this annual report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant s definitive proxy statement relating to the 2013 Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this annual report on Form 10-K relates.

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MATADOR RESOURCES COMPANY

FORM 10-K

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012

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Cautionary Note Regarding Forward-Looking Statements

Certain statements in this Annual Report on Form 10-K constitute forward-looking statements within the meaning of applicable U.S. securities legislation. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as anticipate, believe, continue, could, estimate, expect, intend, may, might, potential, predict, project, should or other similar words.

By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: changes in oil or natural gas prices, the success of our drilling program, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Annual Report on Form 10-K and in other documents that we file with or furnish to the U.S. Securities and Exchange Commission (the SEC), all of which are difficult to predict. Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;

our drilling of wells;

government regulation and taxation of the oil and natural gas industry;

our marketing of oil and natural gas;

our exploitation projects or property acquisitions;

our costs of exploiting and developing our properties and conducting other operations;

general economic conditions;

competition in the oil and natural gas industry;

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- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;
- estimated future reserves and the present value thereof; and
- our plans, objectives, expectations and intentions contained in this Annual Report on Form 10-K that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

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PART I

Item 1. Business.

In this Annual Report on Form 10-K, references to we, our or the Company refer to Matador Resources Company and its subsidiaries before the completion of our corporate reorganization on August 9, 2011 and Matador Holdco, Inc. and its subsidiaries after the completion of our corporate reorganization on August 9, 2011. Prior to August 9, 2011, Matador Holdco, Inc. was a wholly-owned subsidiary of Matador Resources Company, now known as MRC Energy Company. Pursuant to the terms of our corporate reorganization, former Matador Resources Company became a wholly-owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

Unless the context otherwise requires, the term common stock refers to shares of our common stock after the conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering on February 7, 2012, as the Class A common stock then became the only class of common stock authorized, and the term Class A common stock refers to shares of our Class A common stock prior to the automatic conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering.

For certain oil and natural gas terms used in this Annual Report on Form 10-K, see the Glossary of Oil and Natural Gas Terms included in this Annual Report on Form 10-K.

General

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with a particular emphasis on oil and natural gas shale plays and other unconventional resource plays. Our current operations are focused primarily on the oil and liquids rich portion of the Eagle Ford shale play in South Texas and in the Haynesville shale play in Northwest Louisiana. In 2012, more than 90% of our total capital expenditures of $334.6 million were directed to our operations in South Texas, primarily in the Eagle Ford shale, as we sought to transition to a more balanced commodity portfolio through the drilling of wells that were prospective for oil and liquids. For the year ended December 31, 2012, approximately 37% of our total production by volume (using a conversion ratio of one Bbl of oil per 6 Mcf of natural gas) and 79% of our total oil and natural gas revenues were attributable to oil production, primarily from the Eagle Ford shale. In 2013, we expect that approximately 82% of our estimated capital expenditures of $310.0 million will be directed to increasing our oil production and oil reserves in South Texas, primarily in the Eagle Ford shale play. Although we did not drill any operated Haynesville shale natural gas wells during 2012, we directed approximately 3% of our capital expenditures to the Haynesville shale in 2012 to participate in several non-operated wells. In addition to these primary operating areas, we have a growing acreage position in Southeast New Mexico and West Texas where we plan to drill three exploratory wells to test the Wolfcamp and Bone Spring plays during 2013. We also have a large exploratory leasehold position in Southwest Wyoming and adjacent areas in Utah and Idaho where we are testing the Meade Peak shale.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman, President and CEO. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown, Inc., in an all cash transaction for an enterprise value of approximately $388.5 million.

On February 2, 2012, our common stock began trading on the NYSE under the symbol MTDR. On February 7, 2012, we completed our initial public offering of 14,883,334 shares of common stock at $12.00 per share. We sold 12,209,167 shares of common stock in this offering and certain selling shareholders sold 2,674,167 shares of common stock, including shares sold pursuant to the partial exercise of the underwriters over-allotment option on March 7, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

In 2012, our operations were primarily focused on the exploration and development of our Eagle Ford shale properties in South Texas, as we continued to execute our strategy to significantly increase our oil production and oil reserves during 2012. During the year ended December 31, 2012, we completed and began producing oil and natural gas from 28 gross/24.5 net Eagle Ford shale wells, including 25 gross/23.7 net operated and 3 gross/0.8 net non-operated Eagle Ford shale wells. We also completed and began producing oil and natural gas from 2 gross/2.0 net wells in the upper Austin Chalk and the lower Austin Chalk/upper Eagle Ford, or Chalkleford, intervals in 2012. In addition, during 2012, we completed and began producing natural gas from 28 gross/1.1 net non-operated Haynesville shale wells. We also re-entered and drilled a horizontal lateral from the previously suspended Crawford Federal #1 vertical well in Southwest Wyoming; we plan to complete this well in the third quarter of 2013.

We had two contracted drilling rigs operating in South Texas throughout 2012 (except for a brief period near the end of the second quarter when we added a third rig to execute a two-well contract), and almost all of our operated drilling and completion activities were focused on the Eagle Ford shale. We did not drill any operated wells in the Haynesville shale play in Northwest Louisiana during 2012 as a result of the decline in natural gas prices compared to recent years. At March 14, 2013, we continued to have two contracted drilling rigs operating in South Texas: one in LaSalle County and one in DeWitt County.

Our average daily production for the year ended December 31, 2012 was approximately 9,000 BOE per day, including 3,317 Bbl of oil per day and 34.1 MMcf of natural gas per day, as compared to 7,049 BOE per day, including 422 Bbl of oil per day and 39.8 MMcf of natural gas per day for the year ended December 31, 2011. Our total oil production increased almost eight-fold to just over 1.2 million Bbl of oil during the year ended December 31, 2012 from approximately 154,000 Bbl of oil during the year ended December 31, 2011. This increased oil production is a direct result of our drilling operations in the Eagle Ford shale. Oil production comprised approximately 37% of our total production for the year ended December 31, 2012, as compared to only 6% of our total production for the year ended December 31, 2011.

During the three months ended December 31, 2012, specifically, our average daily production was 10,385 BOE per day, including 4,630 Bbl of oil per day and 34.5 MMcf of natural gas per day. This was an increase of almost 50% compared to our average daily production for the three months ended December 31, 2011 of 6,953 BOE per day, including 448 Bbl of oil per day and 39.0 MMcf of natural gas per day. Our total oil production increased ten-fold to 426,000 Bbl of oil during the three months ended December 31, 2012, as compared to total oil production of 41,000 Bbl of oil during the three months ended December 31, 2011. Our average daily production for the fourth quarter of 2012 was a sequential increase of 18% from the average daily production of 8,838 BOE per day, including 3,291 Bbl of oil per day and 33.3 MMcf of natural gas per day, achieved during the third quarter of 2012. For the three months ended December 31, 2012, our oil production grew 41% sequentially, as compared to the three months ended September 30, 2012.

At December 31, 2012, our estimated total proved reserves were 23.8 million BOE, including 10.5 million Bbl of oil and 80.0 Bcf of natural gas (13.3 million BOE). At December 31, 2012, 58% of our total proved reserves were proved developed reserves compared to 34% at December 31, 2011. At December 31, 2012, 44% of our total proved reserves were oil and 56% of our total proved reserves were natural gas, as compared to 12% oil and 88% natural gas at December 31, 2011. Our proved oil reserves grew 176% (almost three-fold) from 3.8 million Bbl at December 31, 2011 to 10.5 million Bbl at December 31, 2012. This growth in oil reserves was attributable to our drilling program in the Eagle Ford shale during 2012. Our proved natural gas reserves declined to 80.0 Bcf at December 31, 2012 from 170.4 Bcf at December 31, 2011. As a result of substantially lower natural gas prices in 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, and these proved undeveloped reserves were likewise not included in our estimated total proved reserves at December 31, 2012. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

The PV-10 of our estimated total proved reserves was $423.2 million at December 31, 2012 compared to a PV-10 of $248.7 million at December 31, 2011, an increase of 70% despite lower commodity prices used to estimate PV-10 in 2012 compared to 2011. The PV-10 at December 31, 2012 was determined using the 12-month unweighted average of first-day-of-the-month oil and natural gas prices for 2012 of $91.21 per barrel and $2.757 per MMBtu, respectively, adjusted by lease for quality, energy content, regional price differentials and other expenses as needed compared to average oil and natural gas prices of $92.71 per barrel and $4.118 per MMBtu, respectively, adjusted as further described above, used to determine PV-10 at December 31, 2011. The Standardized Measure of estimated future net cash flows from our total proved reserves, including estimated future income tax expenses, was $394.6 million at December 31, 2012 and $215.5 million at December 31, 2011. Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see Estimated Proved Reserves.

For the year ended December 31, 2012, our oil and natural gas revenues were approximately $156.0 million, or an increase of about 133%, as compared to approximately $67.0 million for the year ended December 31, 2011. Our oil revenues increased over eight-fold to approximately $123.7 million for the year ended December 31, 2012, as compared to $14.5 million for the year ended December 31, 2011. Our total realized revenues for 2012, including realized gain on derivatives, were approximately $170.0 million, or an increase of about 129%, as compared to $74.1 million for 2011. For the year ended December 31, 2012, our Adjusted EBITDA was approximately $115.9 million, or an increase of about 132%, as compared to an Adjusted EBITDA of approximately $49.9 million for the year ended December 31, 2011. Adjusted EBITDA is a non-GAAP financial measure. For a reconciliation of Adjusted EBITDA to net income (loss) and net cash flow provided by operating activities, see Selected Financial Data Non-GAAP Financial Measures.

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The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2012:

		Producing Wells		Total Identified Drilling Locations[1]		Estimated Net Proved Reserves[2]		Avg. Daily Production (BOE/d)[3]
	Net Acreage	Gross	Net	Gross	Net	MBOE[3]	% Developed	
South Texas:								
Eagle Ford	27,911	37.0	31.7	274.0	221.0	14,331	45.5	3,908
Austin Chalk[4]	17,465	4.0	4.0	17.0	17.0	20	100.0	20
Area Total[5]	27,911	41.0	35.7	291.0	238.0	14,351	45.6	3,928
NW Louisiana/E Texas:								
Haynesville	14,173	134.0	12.7	472.0	101.1	7,856	71.5	4,336
Cotton Valley[6]	22,469	106.0	69.7	71.0	49.3	1,512	100.0	706
Area Total[7]	24,968	240.0	82.4	543.0	150.4	9,368	76.1	5,042
SE New Mexico, West Texas[8]	7,591	13.0	5.7	39.0	25.1	100	100.0	30
SW Wyoming, NE Utah, SE Idaho	27,180							
Total	87,650	294.0	123.8	873.0	413.5	23,819	57.8	9,000

(1) These locations have been identified for potential future drilling and are not currently producing. In addition, the total net identified drilling locations is calculated by multiplying the gross identified drilling locations in an operating area by our working interest participation in such locations. At December 31, 2012, these identified drilling locations included 30 gross and 26.8 net locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 2 gross and 1.9 net locations to which we have assigned proved undeveloped reserves in the Haynesville. We had no proved undeveloped reserves assigned to identified drilling locations in the Austin Chalk or Cotton Valley or in the Wolfcamp or Bone Spring plays in Southeast New Mexico and West Texas at December 31, 2012.

(2) These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Includes two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(5) Some of the same leases cover the net acres shown for both the Eagle Ford formation and the Austin Chalk formation, a shallower formation than the Eagle Ford formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for South Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(7) Some of the same leases cover the net acres shown for both the Haynesville formation and the Cotton Valley formation, a shallower formation than the Haynesville formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for Northwest Louisiana and East Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

(8)

Includes potential future drilling locations identified in either the Wolfcamp or Bone Spring plays on our acreage in Southeast New Mexico and West Texas at December 31, 2012.

At December 31, 2012, our properties included approximately 42,500 gross acres and 27,900 net acres in the Eagle Ford shale play in Atascosa, DeWitt, Gonzales, Karnes, LaSalle, Wilson and Zavala Counties in South Texas. We believe that approximately 88% of our Eagle Ford acreage is prospective predominantly for oil or liquids production. In addition, we believe that portions of this acreage may also be prospective for other targets, such as the Austin Chalk, Buda, Edwards and Pearsall formations, from which we would expect to produce predominantly oil and liquids. Approximately 70% of our Eagle Ford acreage was held by production at December 31, 2012, and approximately 84% of our Eagle Ford acreage was either held by production at December 31, 2012 or not burdened by lease expirations before 2014.

At December 31, 2012, we had 37 gross and 31.7 net wells producing from the Eagle Ford shale in South Texas, and we have identified 274 gross locations and 221.0 net locations for potential future drilling on our Eagle Ford acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Eagle Ford wells and other nearby wells based on available public data, drilling densities anticipated on our properties and observed on properties of other operators, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Of the 274 gross and 221.0 net locations identified for potential future drilling in the Eagle Ford shale at December 31, 2012, we consider 155 gross and 125.1 net locations as Tier 1 locations. We define Tier 1 Eagle Ford locations as those locations that we anticipate to have estimated ultimate recoveries of 225,000 Bbl of oil or greater. Of these Tier 1 locations, 115 gross locations and 109.1 net locations would be operated by us. These identified locations presume that we will be able to develop our Eagle Ford properties on 40-acre to 80-acre spacing, depending on the specific property and the wells we have already drilled. We anticipate that our acreage in central and northern LaSalle County and in northern Karnes County can be developed on 40-acre spacing in the Eagle Ford, while our other properties may be more likely developed on 80-acre spacing. We are currently drilling on 80-acre spacing on most of our properties. Although we had not yet drilled any wells on 40-acre spacing at December 31, 2012, we have several tests on less than 80-acre spacing planned on certain of our properties during 2013. We define Tier 2 Eagle Ford locations, including 119 gross and 95.9 net locations, as those locations that we anticipate to have estimated ultimate recoveries of between 150,000 Bbl and 225,000 Bbl of oil, locations that are primarily prospective for natural gas or other locations on properties already held by existing production. At December 31, 2012, Tier 2 locations were identified primarily on our acreage in Zavala County and in southern LaSalle County; we have identified no potential future Eagle Ford drilling locations on our Atascosa County acreage. All of these Tier 2 locations would be operated by us, and approximately 85% of these locations are located on properties already held by production from the Eagle Ford or other producing horizons. Although we have no plans to drill any of these Tier 2 locations in 2013, as long as these properties remain held by production, these locations remain available for us to drill at a later time should commodity prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries. Certain of these properties, such as our properties in Zavala and Atascosa Counties, also offer the opportunity to explore horizons other than the Eagle Ford, including the Austin Chalk, Buda, Edwards or Pearsall, and we may develop new prospects on these properties in the future. As we explore and develop all of our Eagle Ford acreage further, we believe it is possible that we may identify additional locations for future drilling, particularly on those properties where we now presume development on 80-acre spacing. At December 31, 2012, these 274 gross and 221.0 net potential future drilling locations included 30 gross and 26.8 net locations to which we have assigned proved undeveloped reserves.

In addition, at December 31, 2012, we had approximately 22,300 gross acres and 14,200 net acres in the Haynesville shale play, primarily in Northwest Louisiana. Based on our analysis of geologic and petrophysical information (including total organic carbon content and maturity, resistivity, porosity and permeability, among other information), well performance data, information available to us related to drilling activity and results from wells drilled across the Haynesville shale play, approximately 5,700 of our net acres are located in what we believe is the core area of the play. We believe the core area of the play includes that area in which the most Haynesville wells have been drilled by operators and from which we anticipate natural gas recoveries would likely exceed 6 Bcf per well. Almost all of our Haynesville acreage is held by production from the Haynesville or other formations, and we believe much of it is also prospective for the Cotton Valley, Hosston (Travis Peak) and other shallower formations. In addition, we believe approximately 1,700 of these net acres are prospective for the Middle Bossier shale play, although as of December 31, 2012, we had not tested the Middle Bossier shale on our acreage.

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At December 31, 2012, we had identified 472 gross locations and 101.1 net locations for potential future drilling on our Haynesville acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Haynesville wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, including on some of our non-operated properties, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface conditions, among other criteria. Of the 472 gross locations identified for future drilling, 397 of these locations (50.2 net locations) have been identified within the approximately 5,700 net acres that we believe are located in the core area of the Haynesville play. As we explore and develop our Haynesville acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2012, these identified potential future drilling locations included only 2 gross and 1.9 net locations in the Haynesville shale play to which we have assigned proved undeveloped reserves. As a result of substantially lower natural gas prices in 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties, including 100 gross and 14.8 net locations to which we had previously assigned proved undeveloped reserves. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes and the corresponding potential drilling locations remain available to be developed by us or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

At December 31, 2012, our properties also included approximately 15,900 gross and 7,600 net acres in the Delaware Basin in Southeast New Mexico and West Texas where we are developing new oil prospects. We believe that approximately 8,200 gross and 5,500 net acres are prospective for the Wolfcamp shale and Bone Spring formations, as well as other potential uphole targets including the Delaware sands and the Avalon shale. We believe that the Wolfcamp, Bone Spring, Avalon and Delaware formations are all prospective primarily for oil and that multiple target intervals may be prospective within each formation. At December 31, 2012, approximately 6,000 gross and 3,900 net of these acres were already held by production from other producing horizons. We expect to begin exploring this acreage position during the second and third quarters of 2013 and plan to drill a total of three test wells on this acreage in 2013. Two wells will test the Wolfcamp shale and one well will test the Second Bone Spring formation. At December 31, 2012, we had identified 39 gross and 25.1 net locations for potential future drilling in the Wolfcamp or Bone Spring plays on our acreage in Southeast New Mexico and West Texas, including the three exploratory test wells planned for 2013. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from nearby wells producing from the Wolfcamp and Bone Spring formations based on available public data, drilling densities observed on properties of other operators, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Because we are just beginning the exploration of our properties in Southeast New Mexico and West Texas in 2013, our identified well locations at December 31, 2012 presume that only one horizon in the Wolfcamp or the Bone Spring may be developed at any one surface location and that these properties may be developed on 160-acre well spacing, although we believe that multiple intervals may be prospective at any one surface location and that denser well spacing may be possible. In addition, although our potential future drilling locations presume the drilling of horizontal wells, we also believe that certain portions of our acreage could lend itself to development with vertical wells. As a result, as we explore and develop our Southeast New Mexico and West Texas acreage further, we believe it is possible that we may identify additional locations

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for future drilling. At December 31, 2012, we had not assigned proved undeveloped reserves to any of these potential drilling locations in the Wolfcamp or Bone Spring formations. Although we believe that prospective well locations exist on this acreage for the Avalon shale and the Delaware sands, we had not included any Avalon or Delaware locations in our identified well locations at December 31, 2012.

At December 31, 2012, we also had a large unevaluated acreage position, including approximately 55,300 gross and 27,200 net acres in Southwest Wyoming and adjacent areas in Utah and Idaho, where we began drilling our initial well in February 2011 to test the Meade Peak natural gas shale. We reached a depth of 8,200 feet, approximately 300 feet above the top of the Meade Peak shale, before having operations suspended for several months due to wildlife restrictions. We resumed operations on this initial test well in September 2011 and completed drilling and coring operations in November 2011. After taking time to review and analyze the extensive well log and core data collected in this well, we re-entered the vertical well and drilled an approximately 2,500-ft horizontal lateral in the Meade Peak shale during the fourth quarter of 2012. Operations on this well are temporarily suspended, but we plan to complete and test the horizontal lateral portion of this well beginning in the third quarter of 2013.

We are active both as an operator and as a co-working interest owner with larger industry participants, including affiliates of EOG Resources, Inc., Royal Dutch Shell plc, Chesapeake Energy Corporation and others. At December 31, 2012, we were the operator for approximately 91% of our Eagle Ford and 70% of our Haynesville acreage, including approximately 22% of our acreage in what we believe is the core area of the Haynesville play. A large portion of our acreage in the core area of the Haynesville shale is operated by a subsidiary of Chesapeake Energy Corporation. We also operate the vast majority of our acreage in Southeast New Mexico and West Texas, as well as all of our acreage in Southwest Wyoming and the adjacent areas of Utah and Idaho. In those wells where we are not the operator, our working interest is relatively small, particularly in the Haynesville shale.

At December 31, 2012, we were a non-operating working interest participant with affiliates of Chesapeake Energy Corporation, Royal Dutch Shell plc and several other companies in the Haynesville shale and with EOG Resources, Inc. and Hunt Oil Company in the Eagle Ford shale. We have entered into a joint operating agreement with an affiliate of Chesapeake Energy Corporation governing the Haynesville operations underlying our Elm Grove/Caspiana properties in Southern Caddo Parish, Louisiana and joint operating agreements with EOG Resources, Inc. and Hunt Oil Company governing operations on our joint acreage in Atascosa and Wilson Counties, Texas, respectively. We have not entered into a joint operating agreement with Royal Dutch Shell plc or certain other operators of wells in the Haynesville area in which we have a minority working interest. Particularly when our working interest is small, we do not always enter into formal operating agreements with the operators, and in such cases, we rely on applicable legal and statutory authority to govern our arrangement in accordance with industry standard practices.

Where we do have joint operating agreements with affiliates of other companies, these agreements call for significant penalties should we elect not to participate in the drilling and completion of a well proposed by the operator, or a non-consent well. These non-consent penalties typically allow the operator to recover up to 400% of its costs to drill, complete and equip the non-consent well from the well s future net revenue prior to us being allowed to participate in the non-consent well for our original working interest. Ultimately, the amount of these penalties may result in us having no participation at all in the non-consent well. We also have the right to propose wells under these joint operating agreements, and the same non-consent penalties apply to the operator should it elect not to consent to a well that we propose.

While we do not have direct access to our operating partners drilling plans with respect to future well locations, we do attempt to maintain ongoing communications with the technical staff of these operators in an effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of any related proved undeveloped well locations and reserves. We review these locations with Netherland, Sewell & Associates, Inc., independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

We currently intend to allocate approximately 82% of our estimated 2013 capital expenditure budget of $310.0 million to the exploration, development and acquisition of additional interests in South Texas, primarily in the Eagle Ford shale play. We also plan to allocate about 16% of our 2013 capital expenditure budget to the exploration and acquisition of additional interests in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. As a result of these anticipated capital expenditures in South Texas and in Southeast New Mexico and West Texas, we plan to dedicate about 98% of our 2013 anticipated capital expenditure budget to opportunities prospective for oil and liquids production. While we have budgeted approximately $310.0 million for 2013, the aggregate amount of capital we will expend may fluctuate materially based on market conditions, the actual costs to drill scheduled wells, our drilling results and our ability to obtain capital. Since approximately 84% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2014, 79% of our Wolfcamp and Bone Spring acreage was either held by production or not burdened by lease expirations before 2014 and almost all of our Haynesville acreage was held by production at December 31, 2012, we possess the financial flexibility to allocate our capital when and where we believe it is economical and justified.

Recent Developments

On March 11, 2013, the borrowing base under our Credit Agreement was increased to $255.0 million based on the lenders review of our proved oil and natural gas reserves at December 31, 2012. At that time, we also amended our Credit Agreement to include Capital One, N.A., BMO Harris Financing, Inc. (Bank of Montreal) and IberiaBank in our lending group, which also includes Royal Bank of Canada (RBC), as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia and SunTrust Bank. At March 14, 2013, we had $180.0 million in borrowings and $1.3 million in letters of credit outstanding under our Credit Agreement.

Principal Areas of Interest

Our focus since inception has been the exploration for oil and natural gas in unconventional resource plays with a particular focus in recent years in the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana. During 2012, we devoted most of our efforts and most of our capital investment to our drilling operations in the Eagle Ford shale in South Texas as we sought to increase our oil production and reserves. Since our inception, our exploration efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions. We have also sought to balance the risk profile of our prospects, as well as to explore for more conventional targets in addition to the unconventional resource plays.

At December 31, 2012, our principal areas of interest consisted of (1) the Eagle Ford shale play in South Texas, (2) the Haynesville shale play, including the Middle Bossier shale play, as well as the traditional Cotton Valley and Hosston (Travis Peak) formations in Northwest Louisiana and East Texas, (3) the Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas, particularly in the Delaware Basin, and (4) the Meade Peak shale play in Southwest Wyoming and the adjacent areas of Utah and Idaho.

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South Texas

Eagle Ford Shale and Other Formations

The Eagle Ford shale extends across portions of South Texas from the Mexican border into East Texas forming a band roughly 50 to 100 miles wide and 400 miles long. The Eagle Ford is an organically rich calcareous shale and lies between the deeper Buda limestone and the shallower Austin Chalk formation. Along the entire length of the Eagle Ford trend, the structural dip of the formation is consistently down to the south with relatively few, modestly sized structural perturbations. As a result, depth of burial increases consistently southwards along with the thermal maturity of the formation. Where the Eagle Ford is shallow, it is less thermally mature and therefore more oil prone, and as it gets deeper and becomes more thermally mature, the Eagle Ford is more natural gas prone. The transition between being more oil prone and more natural gas prone includes an interval that typically produces wet natural gas with condensate. We believe that approximately 88% of our South Texas acreage at December 31, 2012 lies within those portions of the Eagle Ford shale that are prone to produce oil or wet natural gas with condensate.

During 2012, our operations were primarily focused on the exploration and development of our Eagle Ford shale properties in South Texas as we continued executing our strategy to significantly increase our oil production and oil reserves. In 2012, we completed and began producing oil and natural gas from 28 gross/24.5 net operated Eagle Ford shale wells, including 25 gross/23.7 net operated and 3 gross/0.8 net non-operated Eagle Ford shale wells. We had two contracted drilling rigs operating in South Texas throughout 2012 (except for a brief period near the end of the second quarter when we added a third rig to execute a two-well contract). At March 14, 2013, we continued to have two contracted drilling rigs operating in South Texas: one in LaSalle County and one in DeWitt County. More than 90% of our 2012 total capital expenditures of $334.6 million were directed to our operations in South Texas, primarily in the Eagle Ford shale.

For the year ended December 31, 2012, about 43% of our daily production, or 3,908 BOE per day, including 3,246 Bbl of oil per day and 4.0 MMcf of natural gas per day, was produced from the Eagle Ford shale in South Texas. Almost all of our oil production in 2012 was attributed to the Eagle Ford shale. The Eagle Ford contributed 98% of our daily oil production and about 12% of our daily natural gas production during 2012 as compared to 78% of our daily oil production and 3% of our daily natural gas production during 2011. During the year ended December 31, 2011, only about 8% of our daily production, or 548 BOE per day, including 331 Bbl of oil per day and 1.3 MMcf of natural gas per day, was attributable to the Eagle Ford shale. This growth in oil and natural gas production from the Eagle Ford shale over the past year reflects our ongoing drilling and completion program in the Eagle Ford shale.

At December 31, 2012, approximately 60% of our estimated total proved oil and natural gas reserves, or 14.3 million BOE, was attributable to the Eagle Ford shale, including approximately 10.4 million Bbl of oil and 23.8 Bcf of natural gas. Our proved reserves attributable to the Eagle Ford shale increased just over three-fold for the year to 14.3 million BOE for the year ended December 31, 2012, as compared to 4.7 million BOE for the year ended December 31, 2011. Our Eagle Ford proved reserves at December 31, 2012 comprised approximately 99% of our proved oil reserves and 30% of our proved natural gas reserves, as compared to approximately 96% of our proved oil reserves and 4% of our proved natural gas reserves at December 31, 2011. The PV-10 of our proved reserves in the Eagle Ford at December 31, 2012 was $393.2 million, or about 93% of the PV-10 of our total proved reserves of $423.2 million. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see Estimated Proved Reserves. We anticipate that the percentage of our daily production and proved reserves attributable to the Eagle Ford shale will continue to grow in 2013 as we intend to allocate approximately 82% of our 2013

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capital expenditure budget to the exploration, development and acquisition of additional interests in South Texas, primarily in the Eagle Ford shale play, in an effort to continue growing the oil and liquids component of our production and reserves.

At December 31, 2012, we had drilled and completed a total of 32 gross/30.5 net Eagle Ford wells on our operated properties, and all of these wells were producing to sales. At December 31, 2012, we had also participated in 3 gross/0.6 net Eagle Ford wells with EOG Resources, Inc. as operator, on portions of our Atascosa County acreage and 2 gross/0.6 net Eagle Ford wells with Hunt Oil Company as operator, on portions of our Wilson County acreage.

During the year ended December 31, 2012, we completed and began producing oil and natural gas from 25 gross/23.7 net operated Eagle Ford wells drilled on our acreage position in South Texas. As we completed and began producing oil and natural gas from these wells during 2012, our Eagle Ford production increased significantly. During the fourth quarter of 2011, our daily production from the Eagle Ford shale averaged 584 BOE per day, including 378 Bbl of oil per day and 1.2 MMcf of natural gas per day. By comparison, during the fourth quarter of 2012, our daily oil production from the Eagle Ford shale averaged 5,363 BOE per day, including 4,545 Bbl of oil per day and 4.9 MMcf of natural gas per day. Natural gas produced from most of our Eagle Ford shale wells is a liquids-rich gas and our purchasers process this natural gas for us at their processing facilities to remove the natural gas liquids, such as ethane, propane and other heavier natural gas liquids components. Our Eagle Ford wells typically yield three to seven gallons of natural gas liquids per thousand cubic feet of natural gas produced at the wellhead depending on the specific property.

During the year ended December 31, 2012, we believe that we increased our technical knowledge on how to drill, complete and produce Eagle Ford shale wells. Eagle Ford wells drilled on the eastern portion of our acreage in Karnes and DeWitt Counties are typically 1,000 to 2,500 feet deeper than wells drilled on the western portion of our acreage in LaSalle County. At December 31, 2012, the typical drilling time for wells on the western portion of our acreage ranged from 10 to 15 days from spud to rig release and the typical drilling time for wells on the eastern portion of our acreage ranged from 15 to 20 days from spud to rig release. These drilling times compared to 20 to 30 days from spud to rig release for wells drilled in the earlier months of 2012. As a result of more efficient drilling and reduced completion costs, the overall drilling and completion costs associated with our Eagle Ford wells declined during 2012. At December 31, 2012, we estimate that the cost for us to drill and complete a 5,000-ft Eagle Ford shale well was approximately $6 million to $7 million on the western portion of our acreage in LaSalle County and approximately $8 million to $10 million on the eastern portion of our acreage in Karnes and DeWitt Counties. We believe the reduction in drilling and completion costs we achieved during 2012 was due in part to improved efficiencies in our own operations, as well as to declining service costs associated with an increase in the supply of drilling and completion services in South Texas during 2012. We do not anticipate that service costs will decline to the same extent in 2013, although we will continue to look for ways to improve the costs associated with our operations.

At December 31, 2012, our aggregate leasehold interests consisted of approximately 42,500 gross acres and 27,900 net acres in the Eagle Ford shale play in Atascosa, DeWitt, Gonzales, Karnes, LaSalle, Wilson and Zavala Counties in South Texas. We believe portions of this acreage may also be prospective for the Austin Chalk, Buda, Edwards and Pearsall formations, from which we would expect to produce

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predominantly oil and liquids. In particular, the Austin Chalk formation, which is a naturally fractured carbonate typically ranging in thickness from 200 to 400 feet, and the Buda formation, which is a naturally fractured carbonate typically ranging in thickness from 90 to 160 feet, have produced from several fields on or nearby portions of our acreage.

During the year ended December 31, 2012, we acquired approximately 5,500 gross and 3,400 net acres in the Eagle Ford shale play that we consider to be prospective primarily for oil production. This acreage essentially replaced the acreage upon which we drilled and established oil and natural gas production and reserves during 2012. We also allowed approximately 11,800 gross and 4,300 net acres of our Eagle Ford leasehold position, primarily in Atascosa County, but also including acreage in northeast Webb and southeast Dimmit Counties, to expire undrilled during the year ended December 31, 2012, as we no longer considered this acreage to be economic for further exploration and development in the Eagle Ford shale at then-current commodity prices.

At December 31, 2012, we owned a 100% working interest in approximately 26,900 gross acres and 24,100 net acres in Gonzales, Karnes, LaSalle, Wilson and Zavala Counties and a 50% working interest in approximately 2,800 gross and 1,400 net acres in DeWitt County and are the operator of this acreage. We also owned an approximate 21% working interest in approximately 12,800 gross acres in Atascosa County operated by EOG Resources, Inc. At December 31, 2012, approximately 84% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2014.

Between March and July 2011, we acquired leasehold interests in approximately 6,300 gross and 4,800 net acres in DeWitt, Gonzales, Karnes and Wilson Counties in the Eagle Ford shale play from Orca ICI Development, JV (Orca). We initially acquired a 50% working interest in the acreage (approximately 2,800 gross and 1,400 net acres) in DeWitt County and are the operator. We currently own a 100% working interest in the acreage (approximately 3,500 gross and 3,400 net acres) in Gonzales, Karnes and Wilson Counties and are the operator. At December 31, 2012, we had drilled and completed 15 gross/12.7 net wells on this acreage.

At December 31, 2012, we had paid 100% of the costs to drill and complete the first six wells drilled on the acreage in DeWitt County. We have an 85% working interest in these six wells until we have recovered all of our acquisition, drilling, completion, facilities and operating costs from each well, at which time Orca s working interest will increase to 50%. After we have recovered all of our acquisition, drilling, completion, facilities and operating costs, when the cumulative production from any of these first six wells reaches 500,000 BOE, on a well-by-well basis, then Orca s working interest in that well will increase to 55%. If the cumulative production from any of the first six wells reaches 750,000 BOE, on a well-by-well basis, then Orca s working interest in that well will increase to 70%. Orca retains the right to pay its share of the costs and to participate for a 50% working interest in all subsequent wells drilled on the acreage in DeWitt County, and we have no further obligation to carry any of Orca s costs in any subsequent well drilled on the acreage. Should Orca elect not to participate in a subsequent well that we propose to drill on the acreage, we will own a 100% working interest in the well until such time as we have recovered 400% of our acquisition, drilling, completion, facilities and operating costs from such well, at which time Orca s working interest will increase to 50%. As of December 31, 2012, Orca had declined to participate in one subsequent well we drilled in DeWitt County, and we own an initial 100% working interest in this well.

At December 31, 2012, we had paid 100% of the costs to drill and complete the first five wells drilled on the acreage in Gonzales, Karnes and Wilson Counties. We have a 100% working interest in these wells until we have recovered all of our acquisition, drilling, completion, facilities and operating costs from each of these five wells. After we have recovered all of our acquisition, drilling, completion, facilities and

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operating costs from any of these five wells, Orca may elect, on a well-by-well basis, to back-in for a 25% working interest in such wells. In addition, Orca retained a one-time election for a short period of time after we completed these first five wells to participate for a 25% working interest in all subsequent wells drilled on this acreage by paying a purchase price equal to 25% of our costs to acquire the acreage in Gonzales, Karnes and Wilson Counties. Following the completion of these first five wells, Orca declined to exercise its right to participate in all future wells drilled on this acreage. As a result, we will have a 100% working interest, and Orca will have no interest, in all subsequent wells drilled on this acreage. At December 31, 2012, we had drilled or participated in a total of 8 gross/6.6 net wells on this specific acreage.

As we continue to explore and develop our leasehold positions in the Eagle Ford shale in South Texas, we may face challenges with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to process, transport and market the oil and natural gas we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout the area. We believe that we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations. We did not experience difficulties in securing completion, and in particular hydraulic fracturing, services for our newly drilled wells during the year ended December 31, 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. We believe that maintaining reliable and timely drilling and completion services and reducing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford shale play. See Risk Factors The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans Within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows.

We did experience temporary pipeline and natural gas processing interruptions from time to time during the year ended December 31, 2012 associated with natural gas production from our Eagle Ford shale wells. To alleviate most of the interruptions and processing capacity constraints we experienced during 2012, effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement whereby we committed to transport the anticipated natural gas production from a significant portion of our Eagle Ford acreage in South Texas through the counterparty s system for processing at the counterparty s facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty s processing plant downstream for fractionation. No assurance can be made that this agreement will alleviate these issues completely, and if we were required to shut in our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it would have a material adverse effect on our business, financial condition, results of operations and cash flows. We may experience similar interruptions and processing capacity constraints as we begin to explore and develop our Wolfcamp and Bone Spring plays in Southeast New Mexico and West Texas in 2013. See Risk Factors The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Gathering, Processing and Transportation Arrangements Would Have a Material Adverse Effect on Our Revenue.

In addition to the Eagle Ford potential on our acreage, we believe that approximately 22,800 gross acres and 17,500 net acres in South Texas are prospective primarily for the Austin Chalk and 15,600 gross and 10,500 net acres are prospective primarily for the Buda formation, which have historically been targeted by operators in South Texas. During the year ended December 31, 2012, we completed and began

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producing oil and natural gas from 2 gross/2.0 net wells in the upper Austin Chalk and the lower Austin Chalk/upper Eagle Ford, or Chalkleford, intervals. Both of these wells were drilled on our acreage in Zavala County, which is in the heart of the historic Pearsall (Austin Chalk) Field where significant volumes of oil and natural gas have previously been produced from the Austin Chalk. Both of these wells are producing oil, but the results of these wells did not meet our expectations, with the upper Austin Chalk well apparently largely depleted by previous Austin Chalk production from nearby wells. We have not yet drilled an Austin Chalk well at any other location on our leasehold positions in South Texas, and although we believe that other prospective Austin Chalk well locations exist on this acreage, we have only included 17 gross and 17.0 net Austin Chalk well locations in our total identified drilling locations at December 31, 2012. We plan to drill an operated Austin Chalk exploratory test well on one of our leases in Gonzales County during 2013. At December 31, 2012, we had not included any Buda locations in our identified future drilling locations, although we do plan to participate in the drilling of an exploratory Buda test well on one of our leases in Atascosa County operated by EOG Resources, Inc. during the first quarter of 2013.

Northwest Louisiana and East Texas

As a result of substantially lower natural gas prices in 2012, we did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during the year ended December 31, 2012. We did, however, participate in the drilling and completion of 28 gross/1.1 net non-operated Haynesville shale wells in 2012, comprising about 3% of our total capital expenditures. We do not plan to drill any operated Haynesville wells in 2013, but we have budgeted capital expenditures of approximately $5.1 million for our participation in approximately 10 gross/0.5 net wells that we anticipate may be drilled by other operators on certain of our non-operated properties in 2013. We operate all of our Cotton Valley and shallower production on our leasehold interests in Northwest Louisiana and East Texas, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville shale play. Of the approximately 5,700 net acres that we consider to be in the core area of the Haynesville play, we operate about 22% of that acreage.

For the year ended December 31, 2012, about 56% of our average daily production, or 5,042 BOE per day, including 31 Bbl of oil per day and 30.1 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana and East Texas. The vast majority of our natural gas production in 2012 was attributable to these properties. Natural gas production from these properties comprised approximately 88% of our daily natural gas production, but oil production from these properties only comprised about 1% of our daily oil production during 2012, as compared to 96% of our daily natural gas production and 15% of our daily oil production during 2011. During the year ended December 31, 2011, approximately 92% of our daily production, or 6,459 BOE per day, including 64 Bbl of oil per day and 38.4 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas. The decline in oil and particularly natural gas production from these properties over the past year reflects (i) the natural decline in production from these properties, (ii) the voluntary curtailment by the operators of natural gas production from some of our non-operated Haynesville shale wells in Northwest Louisiana at various times during 2012 and (iii) our decision not to drill any operated Haynesville shale or Cotton Valley wells during 2012.

For the year ended December 31, 2012, about 76% of our daily natural gas production, or 26.0 MMcf of natural gas per day, was produced from the Haynesville shale, with another 12%, or 4.1 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations in this area. For the year ended December 31, 2011, about 81% of our daily natural gas production, or 32.3 MMcf of natural gas per day, was produced from the Haynesville shale, with another 15%, or 6.1 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties.

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At December 31, 2012, approximately 33% of our estimated total proved reserves, or 7.9 million BOE, were attributable to the Haynesville shale underlying this acreage with another 6% of our proved reserves, or 1.5 million BOE, associated with the Cotton Valley and shallower formations. As a result of substantially lower natural gas prices in 2012, we removed 97.8 Bcf (or 16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. These proved undeveloped natural gas reserves were likewise not included in our estimated total proved reserves at December 31, 2012. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

During 2012, natural gas prices declined to their lowest levels in many years, ranging from a low of approximately $1.91 per MMBtu in mid-April to a high of approximately $3.90 per MMBtu in late November, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Natural gas prices had declined again since late November 2012, before increasing to $3.81 per MMBtu at March 14, 2013, based upon the NYMEX Henry Hub natural gas futures contract for the earliest delivery date. We would not expect to drill any operated natural gas wells in either our Haynesville or Cotton Valley properties until natural gas prices improve further from these levels, the costs to drill and complete these wells decline further from their recent levels or new technologies are developed that increase expected recoveries. See Risk Factors Our Identified Drilling Locations Are Scheduled out over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling.

Haynesville and Middle Bossier Shales

The Haynesville shale is an organically rich, overpressured marine shale found below the Cotton Valley and Bossier formations and above the Smackover formation at depths ranging from 10,500 to 13,500 feet across a broad region throughout Northwest Louisiana and East Texas, including principally Bossier, Caddo, DeSoto and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. The Haynesville shale produces primarily dry natural gas with almost no associated liquids. The Bossier shale is overpressured and is often divided into lower, middle and upper units. The Middle Bossier shale appears to be productive for natural gas under large portions of DeSoto, Red River and Sabine Parishes in Louisiana and Shelby and Nacogdoches Counties in Texas, where it shares many similar productive characteristics with the deeper Haynesville shale. Although there is some overlap between the Haynesville and Bossier shale plays, the two plays appear quite distinct and a separate horizontal wellbore is typically needed for each formation.

At December 31, 2012, we had leasehold and mineral interests in approximately 22,300 gross and 14,200 net acres prospective for the Haynesville shale. This acreage includes approximately 5,700 net acres in what we believe is the core area of the play. Over 99% of our Haynesville acreage is held by production or consists of fee mineral interests that we own and portions of it are also producing from and, we believe, prospective for the Cotton Valley, Hosston (Travis Peak) and other shallower formations. In addition, we believe that approximately 1,700 net acres are prospective for the Middle Bossier shale play as well. We have not yet drilled a Middle Bossier shale well, and, although we believe that prospective well locations exist on this acreage, we have not included any Middle Bossier locations in our identified drilling locations at December 31, 2012.

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Within the 5,700 net acres that we believe to be in the core area of the Haynesville shale play, we are the operator of approximately 1,200 net acres in two sections where we have working interests of 95% and 100%, respectively, in all wells to be drilled. We have identified 12 gross and 11.7 net potential additional Haynesville locations that we may drill and operate in the future in these two sections. The remainder of our acreage in the core area of the Haynesville shale play, about 4,500 net acres, is operated by other companies, including approximately half of our non-operated Haynesville acreage in this area of the play that is operated by a subsidiary of Chesapeake following a sale of a portion of our interest in July 2008. Including the acreage operated by a subsidiary of Chesapeake, our non-operated Haynesville acreage is attributable to leasehold interests that we hold in 81 sections in Caddo, DeSoto, Bossier and Red River Parishes in Northwest Louisiana. Our working interests in the Haynesville wells in these sections range from less than 1% to more than 30%.

Cotton Valley, Hosston (Travis Peak) and Other Shallower Formations

Prior to initiating natural gas production from the Haynesville shale in 2009, almost all of our production and reserves in Northwest Louisiana and East Texas were attributable to wells producing from the Cotton Valley formation. We own almost all of the shallow rights from the base of the Cotton Valley formation to the surface under our acreage in Northwest Louisiana and East Texas.

All of the shallow rights underlying our acreage in our Elm Grove/Caspiana properties in Northwest Louisiana, approximately 10,000 gross and net acres at December 31, 2012, is held by existing production from the Cotton Valley formation or the Haynesville shale. The Cotton Valley formation was the primary producing zone in the Elm Grove field prior to discovery of the Haynesville shale. The Cotton Valley formation is a low permeability natural gas sand that ranges in thickness from 200 to 300 feet and has porosity ranging from 6% to 10%.

In January 2011, we completed our first horizontal Cotton Valley well, the Tigner Walker H #1-Alt. on our Elm Grove/Caspiana properties, in DeSoto Parish and commenced sales of natural gas from this well. Based on the performance of this well and data available from public sources on other Cotton Valley horizontal wells drilled in this area of Northwest Louisiana, we believe that Cotton Valley horizontal wells drilled on our Elm Grove/Caspiana properties may have estimated ultimate natural gas recoveries of 4 to 6 Bcf. Prior to drilling this well, we had only drilled and completed vertical Cotton Valley and Hosston wells on these properties. We are the operator and have a 100% working interest in this well. We have identified 71 gross and 49.3 net additional drilling locations for future Cotton Valley horizontal wells on our Elm Grove/Caspiana properties. We did not drill any of these locations in 2012 and do not plan to drill any of these locations in 2013. As long as this leasehold acreage is held by existing production from the vertical Cotton Valley wells or the deeper Haynesville shale wells, however, these Cotton Valley natural gas volumes remain available to be developed by us at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

We also continue to hold the shallow rights by existing production or by leases that are still in their primary terms in our Central and Southwest Pine Island, Longwood, Woodlawn and other prospect areas in Northwest Louisiana and East Texas. At December 31, 2012, we held an estimated 11,500 net leasehold and mineral acres by existing production in these areas.

Southeast New Mexico and West Texas Delaware Basin

During 2012, we added to our acreage position in the Delaware Basin in Southeast New Mexico and West Texas, which is a mature exploration and production province with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of

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development in this basin has focused on relatively conventional reservoir targets, but we believe the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology is enhancing the development potential of this basin.

One example of such an opportunity appears to be the so-called Wolf-Bone play of the Delaware Basin. Together, the Lower Permian age Bone Spring (also called Leonardian) and Wolfcamp formations span several thousand feet of stacked shales, sandstones, limestones and dolomites, representing complex and dynamic submarine depositional systems that include several organic rich source rocks. Throughout these intervals, oil and natural gas have been produced primarily from conventional sandstone and carbonate reservoirs even though hydrocarbons are trapped in the tight sands, limestones and dolomites interbedded within organic rich shale. Recently, these hydrocarbon-bearing zones have been recognized by a number of operators as targets for horizontal drilling and multi-stage hydraulic fracturing techniques. As a result, several large industry players are expanding positions and conducting drilling programs throughout Eddy and Lea Counties in Southeast New Mexico and Loving, Pecos, Reeves and Ward Counties in West Texas.

For the year ended December 31, 2012, less than 1% of our average daily production, or only about 30 BOE per day, including 25 Bbl of oil per day and 30 Mcf of natural gas per day, was attributable to our leasehold properties in Southeast New Mexico and West Texas. At December 31, 2012, we held leasehold interests in approximately 15,900 gross and 7,600 net acres in Southeast New Mexico and West Texas where we are developing new oil prospects. In particular, in August 2012, we acquired approximately 4,900 gross and 2,900 net acres prospective for the Wolfcamp and Bone Spring formations in Loving County, Texas, almost all of which is held by production from uphole formations to which we did not acquire the exploration and development rights. Subsequent to that time, we have added additional interests in this immediate area and at December 31, 2012, we held approximately 5,200 gross and 3,000 net acres in this leasehold position in Loving County. We have budgeted approximately $15.0 million of our anticipated 2013 capital expenditures to acquire additional leasehold interests prospective for oil and liquids production in Southeast New Mexico and West Texas. A portion of our leasehold interests in this area, including approximately 7,700 gross and 2,100 net acres in Winkler County, Texas, is no longer considered to be prospective by us, and we plan to let this acreage expire without drilling.

At December 31, 2012, we believe that approximately 8,200 gross and 5,500 net acres of our leasehold interests in the Delaware Basin are prospective for the Wolfcamp and Bone Spring formations, as well as other potential uphole targets, including the Avalon shale and Delaware sands, of which approximately 6,000 gross and 3,900 net acres are already held by existing production from other horizons by us or other operators. We believe that the Wolfcamp, Bone Spring, Avalon and Delaware formations are all prospective primarily for oil and that multiple intervals may be prospective within each target formation. We expect to begin exploring this acreage position during the second and third quarters of 2013, with plans to drill three exploratory test wells on this acreage in 2013. We have allocated approximately $35.6 million of our 2013 capital expenditure budget for these drilling and completion operations, including an estimated $5.4 million for pipelines, production facilities and related infrastructure. Two of these wells will test the Wolfcamp and one well will test the Second Bone Spring formation.

Southwest Wyoming, Northeast Utah and Southeast Idaho Meade Peak Shale

The Meade Peak shale is an organic-rich member of the Phosphoria formation, a source rock that is believed to have sourced much of the oil and natural gas in conventional reservoirs in the western Wyoming and eastern Utah area. The Phosphoria/Meade Peak shale has an observed shale thickness of 70 to 350 feet, total organic carbon values of 3% to 14% and vitrinite reflectance values ranging from 1.8% to 2.7%. The

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formation is encountered at depths of 3,000 to 14,000 feet, with the majority of our acreage in the depth range of 3,000 to 10,000 feet. The shale has been penetrated by over 100 wells in the area, most of which have natural gas shows.

We believe there have been no previous attempts to drill horizontally or to hydraulically fracture the Meade Peak shale in this area. Our focus to date has been to confirm the physical characteristics of the Meade Peak shale and evaluate its production potential. We have gathered well log data in the area, conducted a series of mapping evaluations of structural disposition and studied the petrophysical characteristics of the Meade Peak shale. In addition, we have purchased 2-D seismic data and conducted surface mapping studies using a structural geologist who has experience in the immediate area to better understand the area s tectonic history.

At December 31, 2012, we held leasehold interests in approximately 55,300 gross and 27,200 net acres in Southwest Wyoming and adjacent areas in Utah and Idaho as part of a natural gas shale exploration prospect targeting the Meade Peak shale. These leasehold interests are a combination of federal, state and fee mineral interests. We have entered into a participation and joint operating agreement with other parties covering the initial exploration effort, and if successful, the future development of this acreage. We are the operator of this prospect. We had no production, no proved reserves and no identified drilling locations attributable to this acreage at December 31, 2012.

At December 31, 2011, we held leasehold interests in approximately 144,000 gross and 136,000 net acres in this prospect, of which approximately 102,000 gross and 93,000 net acres were scheduled to expire at various times during 2012. Although we elected to take extensions or new leases on some portions of this expiring acreage during 2012, certain leases, particularly those taken on state lands, did not offer the opportunity for automatic extension and expired during 2012. Should we desire to reacquire mineral rights on these lands, we would need to seek new leases.

Along with our partners, we began drilling the initial test well on this prospect, the Crawford Federal #1 well in Lincoln County, Wyoming, in February 2011. We reached a depth of 8,200 feet, approximately 300 feet above the top of the Meade Peak shale, before having operations suspended for several months due to wildlife restrictions. We resumed operations on this initial test well in September 2011 and completed drilling, well logging and coring operations in November 2011. During 2012, we conducted detailed evaluations of the well logs and conducted special core analysis tests to better understand the petrophysical characteristics of the Meade Peak shale.

In September 2012, we entered into an agreement with our principal partner related to the ongoing exploration of the Meade Peak shale, pursuant to which our principal partner (i) paid us a prospect fee of $1.0 million, (ii) agreed to provide up to a total cost of $3.0 million (carrying our 50% share) for extensions of expiring leases and new leasing in the prospect in which we will have a 50% working interest at no cost to us and (iii) agreed to carry our 50% share of the drilling and completion costs associated with the horizontal lateral up to a total cost for these operations of $5.0 million, with each party paying 50% of all drilling and completion costs in excess of $5.0 million. In return for this consideration, in December 2012, we assigned 50% of our gross and net leasehold interests in the prospect to our principal partner.

In November 2012, we re-entered the Crawford Federal #1 vertical well and drilled a horizontal lateral from that wellbore into the Meade Peak shale approximately 2,500 feet in length. We temporarily suspended this well following drilling operations. We expect to return to this well in the third quarter of 2013 to conduct the completion operations on the horizontal lateral, which we expect will consist of three to

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four hydraulic fracture treatments along the length of the lateral. After the horizontal lateral is completed, we and our partners plan to test and evaluate this well before making further decisions concerning the future exploration of the Meade Peak shale in this prospect.

Operating Summary

The following table sets forth certain unaudited production data for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31, 2012	2011	2010
Unaudited Production Data			
Net Production Volumes:			
Oil (MBbl)	1,214	154	33
Natural gas (Bcf)	12.5	14.5	8.4
Total oil equivalent (MBOE)(1)	3,294	2,573	1,433
Average daily production (BOE/d)(1)	9,000	7,049	3,926
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$ 103.55	$ 93.80	$ 76.39
Oil, without realized derivatives (per Bbl)	$ 101.86	$ 93.80	$ 76.39
Natural gas, with realized derivatives (per Mcf)	$ 3.55	$ 4.11	$ 4.38
Natural gas, without realized derivatives (per Mcf)	$ 2.59	$ 3.62	$ 3.75
Operating Expenses (per BOE):			
Production taxes and marketing	$ 3.54	$ 2.44	$ 1.38
Lease operating	$ 8.56	$ 2.82	$ 3.69
Depletion, depreciation and amortization	$ 24.43	$ 12.34	$ 10.89
General and administrative	$ 4.42	$ 5.21	$ 6.77

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2012 from our primary operating areas:

	Average Net Daily Production			Total Net	Percentage of
	Oil (Bbl/d)	Gas (Mcf/d)	Oil Equivalent (BOE/d)(1)	Production (MBOE)(1)	Total Net Production
South Texas:					
Eagle Ford	3,246	3,976	3,908	1,431	43.4%
Austin Chalk(2)	15	31	20	7	0.3
Area Total	3,261	4,007	3,928	1,438	43.7
NW Louisiana/E Texas:					
Haynesville	1	26,007	4,336	1,587	48.2
Cotton Valley(3)	30	4,051	706	258	7.8
Area Total	31	30,058	5,042	1,845	56.0
SE New Mexico, West Texas	25	30	30	11	0.3
SW Wyoming, NE Utah, SE Idaho(4)					
Total	3,317	34,095	9,000	3,294	100.0%

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(2) Includes two wells producing small volumes of natural gas from the San Miguel formation in Zavala County, Texas.

(3) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(4) We currently have no production from our acreage in Southwest Wyoming and adjacent areas of Utah and Idaho.

The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2011 from our primary operating areas:

	Average Net Daily Production			Total Net	Percentage of
	Oil (Bbl/d)	Gas (Mcf/d)	Oil Equivalent (BOE/d)(1)	Production (MBOE)(1)	Total Net Production
South Texas:					
Eagle Ford	331	1,298	548	200	7.8%
Austin Chalk(2)		30	5	2	0.1
Area Total	331	1,328	553	202	7.9
NW Louisiana/E Texas:					
Haynesville		32,319	5,387	1,966	76.4
Cotton Valley(3)	64	6,054	1,072	392	15.2
Area Total	64	38,373	6,459	2,358	91.6
SE New Mexico, West Texas	27	59	37	13	0.5
SW Wyoming, NE Utah, SE Idaho(4)					
Total	422	39,760	7,049	2,573	100.0%

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(2) Includes two wells producing small volumes of natural gas from the San Miguel formation in Zavala County, Texas.

(3) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(4) We currently have no production from our acreage in Southwest Wyoming and adjacent areas of Utah and Idaho.

Our total production of approximately 3.3 million BOE for the year ended December 31, 2012 was an increase of 28% over our total production of approximately 2.6 million BOE for the year ended December 31, 2011. This increased production was primarily due to drilling operations in the Eagle Ford shale. Our average daily production for the year ended December 31, 2012 was 9,000 BOE per day, as compared to 7,049 BOE per day for the year ended December 31, 2011. Our average daily oil production for the year ended December 31, 2012 was 3,317 Bbl of oil per day, an approximate eight-fold increase from 422 Bbl of oil per day for the year ended December 31, 2011.

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Producing Wells

The following table sets forth information relating to producing wells at December 31, 2012. Wells are classified as oil wells or natural gas wells according to their predominant production stream. We do not have any currently active dual completions. We have an approximate average working interest of 93% in all wells that we operate. For wells where we are not the operator, our working interests range from less than 1% to as much as 44%, and average approximately 8%. In the table below, gross wells are the total number of producing wells in which we own a working interest and net wells represent the total of our fractional working interests owned in the gross wells.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	35.0	29.7	2.0	2.0	37.0	31.7
Austin Chalk[(1)]	2.0	2.0	2.0	2.0	4.0	4.0
Area Total	37.0	31.7	4.0	4.0	41.0	35.7
NW Louisiana/E Texas:						
Haynesville			134.0	12.7	134.0	12.7
Cotton Valley[(2)]	2.0	2.0	104.0	67.7	106.0	69.7
Area Total	2.0	2.0	238.0	80.4	240.0	82.4
SE New Mexico, West Texas	12.0	5.1	1.0	0.6	13.0	5.7
SW Wyoming, NE Utah, SE Idaho[(3)]						
Total	51.0	38.8	243.0	85.0	294.0	123.8

(1) Includes two wells producing small volumes of natural gas from the San Miguel formation in Zavala County, Texas.

(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(3) We currently have no production from our acreage in Southwest Wyoming and adjacent areas of Utah and Idaho.

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Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2012, 2011 and 2010. The reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC s rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

	At December 31,[1]		
	2012	**2011**	**2010**
Estimated Proved Reserves Data:[2]			
Estimated proved reserves:			
Oil (MBbl)	10,485	3,794	152
Natural Gas (Bcf)	80.0	170.4	127.4
Total (MBOE)[3]	23,819	32,196	21,387
Estimated proved developed reserves:			
Oil (MBbl)	4,764	1,419	152
Natural Gas (Bcf)	54.0	56.5	43.1
Total (MBOE)[3]	13,771	10,843	7,342
Percent Developed	57.8%	33.7%	34.3%
Estimated proved undeveloped reserves:			
Oil (MBbl)	5,721	2,375	
Natural Gas (Bcf)	26.0	113.9	84.3
Total (MBOE)[3]	10,048	21,353	14,045
PV-10[4] (in millions)	$ 423.2	$ 248.7	$ 119.9
Standardized Measure[5] (in millions)	$ 394.6	$ 215.5	$ 111.1

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the 12 months ended December 31, 2010 were $75.96 per Bbl for oil and $4.376 per MMBtu for natural gas, for the 12 months ended December 31, 2011 were $92.71 per Bbl for oil and $4.118 per MMBtu for natural gas, and for the 12 months ended December 31, 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead.

(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2010, 2011 and 2012 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes

associated with such reserves. The discounted future income taxes at December 31, 2010, 2011 and 2012 were, in millions, $8.8, $33.2, and $28.6, respectively.

(5) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

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Our proved oil reserves grew 176% (almost three-fold) from approximately 3.8 million Bbl at December 31, 2011 to approximately 10.5 million Bbl at December 31, 2012. This increase is attributable to proved oil reserves added due to our drilling operations in the Eagle Ford shale in South Texas. Proved oil reserves at December 31, 2012 comprised 44% of our total proved reserves as compared to only 12% at December 31, 2011.

Our total proved oil and natural gas reserves decreased from 32.2 million BOE at December 31, 2011 to 23.8 million BOE at December 31, 2012, reflecting primarily the decrease in our proved natural gas reserves from 170.4 Bcf at December 31, 2011 to 80.0 Bcf at December 31, 2012. This decrease in our proved natural gas reserves was primarily attributable to the decrease in our proved undeveloped natural gas reserves from 113.9 Bcf at December 31, 2011 to 26.0 Bcf at December 31, 2012. As a result of substantially lower natural gas prices in 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. These proved undeveloped natural gas reserves were likewise not included in our estimated total proved reserves at December 31, 2012. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries. The PV-10 of our total proved oil and natural gas reserves increased by 70% from $248.7 million at December 31, 2011 to $423.2 million at December 31, 2012. Our total proved reserves at December 31, 2012 were made up of approximately 44% oil and 56% natural gas as compared to 12% oil and 88% natural gas at December 31, 2011.

Our proved developed oil and natural gas reserves increased from 10.8 million BOE at December 31, 2011 to 13.8 million BOE at December 31, 2012 due primarily to additions resulting from our drilling operations in the Eagle Ford shale. Our proved developed oil reserves increased from 1.4 million Bbl at December 31, 2011 to 4.8 million Bbl at December 31, 2012 as a result of our drilling operations in the Eagle Ford shale. Our proved developed natural gas reserves declined from 56.5 Bcf (9.4 million BOE) at December 31, 2011 to 54.0 Bcf (9.0 million BOE) at December 31, 2012. The net increase of 3.0 million BOE in our proved developed reserves from December 31, 2011 to December 31, 2012 was composed of (1) additions of 7.4 million BOE, including 4.7 million Bbl of oil and 16.2 Bcf of natural gas (2.7 million BOE), plus conversions of 0.4 million BOE, including 0.3 million Bbl of oil and 0.8 Bcf of natural gas (0.1 million BOE) from proved undeveloped to proved developed reserves, less (2) net oil and natural gas production of 3.3 million BOE, including 1.2 million Bbl of oil and 12.5 Bcf of natural gas (2.1 million BOE), less (3) downward revisions of proved developed reserves by 1.5 million BOE, including 0.5 million Bbl of oil and 6.2 Bcf of natural gas (1.0 million BOE). The downward revisions in proved developed natural gas reserves were primarily attributable to the lower natural gas prices used to estimate proved reserves at December 31, 2012 as compared to December 31, 2011. During the year ended December 31, 2012, we recorded no changes to proved developed reserves as a result of the acquisition or divestment of reserves.

Our proved undeveloped oil and natural gas reserves decreased from 21.4 million BOE at December 31, 2011 to 10.1 million BOE at December 31, 2012. Our proved undeveloped oil reserves increased from 2.4 million Bbl at December 31, 2011 to 5.7 million Bbl at December 31, 2012 as a result of our drilling operations in the Eagle Ford shale. Our proved undeveloped natural gas reserves decreased from 113.9 Bcf (19.0 million BOE) at December 31, 2011 to 26.0 Bcf (4.3 million BOE) at December 31, 2012 due primarily to the removal of 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana as a result of lower natural gas prices in 2012. The net decrease of 11.3 million BOE in our proved undeveloped reserves from December 31,

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2011 to December 31, 2012 is composed of (1) additions to proved undeveloped reserves of 5.5 million BOE, including 4.0 million Bbl of oil and 9.3 Bcf of natural gas (1.5 million BOE) identified through drilling operations, less (2) the conversion of 0.4 million BOE of proved undeveloped reserves to proved developed reserves, including 0.3 million Bbl of oil and 0.8 Bcf of natural gas (0.1 million BOE), less (3) the net downward revisions of proved undeveloped reserves by 16.4 million BOE in the period, including 0.3 million Bbl of oil and 96.4 Bcf (16.1 million BOE). During the year ended December 31, 2012, we recorded no changes to proved undeveloped reserves as a result of the acquisition or divestment of reserves. At December 31, 2012, we had no proved reserves in our estimates that remained undeveloped for five years or more following their initial booking.

The following table sets forth additional summary information by operating area with respect to our estimated net proved reserves at December 31, 2012:

	Net Proved Reserves(1)				
	Oil (MBbl)	**Gas (Bcf)**	**Oil Equivalent (MBOE)(4)**	**PV-10 (2) (in millions)**	**Standardized Measure(3) (in millions)**
South Texas:					
Eagle Ford	10,358	23.8	14,331	393.2	366.6
Austin Chalk(5)	7	0.1	20	0.4	0.4
Area Total	10,365	23.9	14,351	393.6	367.0
NW Louisiana/E Texas:					
Haynesville		47.1	7,856	21.8	20.3
Cotton Valley(6)	34	8.9	1,512	5.8	5.4
Area Total	34	56.0	9,368	27.6	25.7
SE New Mexico, West Texas	86	0.1	100	2.0	1.9
SW Wyoming, NE Utah, SE Idaho(7)					
Total	10,485	80.0	23,819	423.2	394.6

(1) Numbers in table may not total due to rounding.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2012 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2012 were approximately $28.6 million.

(3) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Includes two wells producing small volumes of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(7) At December 31, 2012, we had no proved reserves attributable to our acreage in Southwest Wyoming and adjacent areas of Utah and Idaho.

Technology Used to Establish Reserves

Under current SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations. The term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we used technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and technical data used in the estimation of our proved reserves include, but are not limited to, electric logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production. Non-producing reserves estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods.

Internal Control Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our Reserves Manager is primarily responsible for overseeing the preparation of our reserves estimates and has over 16 years of industry experience. Our Reserves Manager received his Ph.D. degree in Petroleum Engineering from Texas A&M University, is a Licensed Professional Engineer in the State of Texas and received a certificate of completion in a prescribed course of study in Reserves and Evaluation from Texas A&M University in May 2009. Our Vice President Reservoir Engineering is responsible for reviewing and approving our reserves estimates and has over 35 years of industry experience. Following the preparation of our reserves estimates, we had our reserves estimates audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. The Engineering Committee of our board of directors reviews the reserves report and our reserves estimation process, and the results of the reserves report and the independent audit of our reserves are reviewed by members of our board of directors, including members of our Audit Committee.

Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2012. At that date, about 44% of our total net acreage had been developed, although these percentages are somewhat higher in South Texas and much higher in Northwest Louisiana and East Texas.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	18,236	15,736	24,220	12,175	42,456	27,911
Austin Chalk	8,892	8,892	13,893	8,573	22,785	17,465
Area Total[1]	18,236	15,736	24,220	12,175	42,456	27,911
NW Louisiana/E Texas:						